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FORM 10-K

MARINER ENERGY INC - ME

Filed: March 01, 2010 (period: December 31, 2009)

Annual report which provides a comprehensive overview of the company for the past year

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

Form 10-K

- ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2009
- OR
- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-32747

MARINER ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware
*(State or other jurisdiction of
incorporation or organization)*

86-0460233
*(I.R.S. Employer
Identification Number)*

**One BriarLake Plaza, Suite 2000
2000 West Sam Houston Parkway South
Houston, Texas 77042**

(Address of principal executive offices and zip code)

(713) 954-5500

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, \$.0001 par value	New York Stock Exchange
Rights to Purchase Preferred Stock	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

The aggregate market value of the registrant’s common stock held by non-affiliates on June 30, 2009 was approximately \$1,150,891,162 based on the closing sale price of \$11.75 per share as reported by the New York Stock Exchange on June 30, 2009. The number of shares of common stock of the registrant issued and outstanding on February 22, 2010 was 101,780,353.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant’s Proxy Statement relating to the Annual Meeting of Stockholders to be held May 5, 2010 are incorporated by reference into Part III of this Form 10-K.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Various statements in this annual report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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,” “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “plan,” “goal” or other words that convey the uncertainty of future events or outcomes. The forward-looking statements in this annual report speak only as of the date of this annual report; we disclaim any obligation to update these statements unless required by 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 described in “Item 1A. Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” elsewhere in this annual report. 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 events and natural disasters such as loop currents, hurricanes, fires, floods and other natural events, 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;
- risks related to significant acquisitions or other strategic transactions, such as failure to realize expected benefits or objectives for future operations; and
- foreign currency risks.

PART I

The following discussion is intended to assist you in understanding our business and the results of our operations. It should be read in conjunction with the Consolidated Financial Statements and the related notes that appear elsewhere in this report. Certain statements made in our discussion may be forward looking. Forward-looking statements involve risks and uncertainties and a number of factors could cause actual results or outcomes to differ materially from our expectations. See "Cautionary Statements" at the beginning of this report on Form 10-K for additional discussion of some of these risks and uncertainties. Unless the context otherwise requires or indicates, references to "Mariner," "we," "our," "ours," and "us" refer to Mariner Energy, Inc. and its consolidated subsidiaries collectively. Certain oil and natural gas industry terms used in this annual report are defined in the "Glossary of Oil and Natural Gas Terms" set forth in "Item 1. Business" of this annual report.

Item 1. Business.

General

Mariner Energy, Inc. is an independent oil and gas exploration, development, and production company. We were incorporated in August 1983 as a Delaware corporation. Our corporate headquarters are located at One BriarLake Plaza, Suite 2000, 2000 West Sam Houston Parkway South, Houston, Texas 77042. Our telephone number is (713) 954-5500 and our website address is www.mariner-energy.com. Our common stock is listed on the New York Stock Exchange and trades under the symbol "ME."

We currently operate in four principal areas:

- Permian Basin, where we are an active driller in the prolific Spraberry field at depths between 6,000 and 10,000 feet. Our increasing Permian Basin operation, which is characterized by long reserve life, stable drilling and production performance, and relatively lower capital requirements, somewhat counterbalances the higher geological risk, operational challenges and capital requirements attendant to most of our Gulf of Mexico deepwater operations. We have expanded our presence in the region, targeting a combination of infill drilling activities in established producing trends, including the Spraberry, Dean and Wolfcamp trends, as well as exploration activities in emerging plays such as the Wolfberry and newer Wolfcamp trends.
- Gulf Coast, where, in December 2009, we acquired interests predominantly in the Vicksburg, Queen City and Deep Frio producing trends in South Texas. As is the case with our Permian Basin operation, we expect the relatively lower risk and cost of exploiting our Gulf Coast properties to further counterbalance those of our Gulf of Mexico deepwater operations.
- Gulf of Mexico Deepwater, where we have actively conducted exploration and development projects since 1996 in water depths ranging from approximately 1,300 feet up to 7,100 feet. Employing our experienced geoscientists, rich seismic database, and extensive subsea tieback expertise, we have participated in more than 79 deepwater wells. Our deepwater exploration operation targets larger potential reserve accumulations than are generally accessible onshore or on the Gulf of Mexico shelf.
- Gulf of Mexico Shelf, where we drill or participate in conventional shelf wells and deep shelf wells extending to 1,300 foot water depths. We currently pursue a two-pronged strategy on the shelf, combining exploration and exploitation activities targeting conventional and deep shelf opportunities. Given the highly mature nature of this area and the steep production declines characteristic of most wells in this region, the goal of our shallow water or shelf operation is to maximize cash flow for reinvestment in our deepwater and onshore operations, as well as for expansion into new operating areas.

We also are investigating a variety of shale and unconventional resource opportunities in the United States and Canada, such as green field leasing, joint ventures and acquisitions. In 2009, we added a team of approximately 10 geoscientists experienced in unconventional resource plays in those areas. We also formed a Canadian subsidiary which opened an office in Calgary. We initially are targeting liquids-rich plays with

relatively low entry costs in the Rocky Mountains, South Texas and the Permian Basin, including unconventional potential of our existing asset base. During 2009, we acquired working interests in approximately 80,000 (43,000 net) acres in unconventional plays in North Dakota, Wyoming, Arkansas and New Mexico. Our secured revolving credit facility currently limits our investment in our Canadian operation to \$25.0 million.

During 2009, we produced approximately 126.5 Bcfe and our average daily production rate was 347 MMcfe. At December 31, 2009, we had 1.087 Tcfe of estimated proved reserves, of which approximately 56% were onshore (47% in the Permian Basin and 8% in the Gulf Coast), with the balance offshore (15% in the Gulf of Mexico deepwater and 29% on the Gulf of Mexico shelf); 53% were natural gas; and 47% were oil and natural gas liquids (“NGLs”). Approximately 66% of our estimated proved reserves were classified as proved developed.

We file annual, quarterly and current reports, proxy statements and other information as required by the Securities and Exchange Commission (“SEC”). Our SEC filings are available to the public over the Internet at the SEC’s web site at www.sec.gov or at the SEC’s public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information about the public reference room. Reports and other information about Mariner can be inspected at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005. Copies of our SEC filings are available free of charge on our website at www.mariner-energy.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information on our website is not a part of this annual report. Copies of our SEC filings can also be provided to you at no cost by writing or telephoning us at our corporate headquarters.

Recent Developments

Onshore Acquisition — On December 31, 2009, we acquired the reorganized subsidiaries and operations of Edge Petroleum Corporation (“Edge”). The material assets acquired consist primarily of (i) proved reserves estimated by Ryder Scott Company, L.P. as of December 31, 2009 of 100.5 Bcfe, of which approximately 75% are developed (consisting of 69% natural gas and 31% oil and NGLs), 81% are located in South Texas, and 44% are in the Flores/Bloomberg field in Starr County, Texas, (ii) approximately 60,000 net acres of undeveloped leasehold, primarily in Texas and New Mexico, and (iii) deferred tax assets of approximately \$83.3 million, comprised of approximately \$61.2 million in net operating loss carryforwards and \$22.1 million in built-in losses from carryover tax basis in the properties. The effective date of the acquisition was June 30, 2009 and the purchase price was \$260.0 million, less adjustments which resulted in a net purchase price as of December 31, 2009 of approximately \$213.6 million, subject to final adjustments. We financed the net purchase price by borrowing under our secured revolving credit facility.

Balanced Growth Strategy

We are a growth company and strive to increase our reserves and production from our existing asset base as well as through expansion into new operating areas. Our management team pursues a balanced growth strategy employing varying elements of exploration, development, and acquisition activities intended to achieve an overall moderate-risk growth profile at attractive rates of return under most industry conditions.

- *Exploration:* Our exploration program is designed to facilitate organic growth through exploration in a wide variety of exploratory drilling projects, including higher-risk, high-impact projects that have the potential to create substantial value for our stockholders. We view exploration as a core competency. We typically dedicate a significant portion of our capital program each year to prospecting for new oil and gas fields, including in the Gulf of Mexico deepwater where reserve accumulations are typically much larger than those found onshore or on the shelf. Our explorationists have a distinguished track record in the Gulf of Mexico, making a number of significant deepwater discoveries in the Gulf of Mexico in the last five years. In addition, we believe our reputation for generating high-quality exploration prospects creates potentially valuable partnering opportunities, which enables us to participate in exploration projects developed by other operators.

- *Development:* Our development and exploitation efforts are intended to complement our higher-risk, high-impact exploration projects through a variety of moderate-risk activities targeted at maximizing recovery and production from known reservoirs. These activities are also aimed at finding overlooked oil and gas accumulations in and around existing fields and are designed to establish critical operating mass from which to expand in our focus areas. Our geoscientists and engineers have an excellent track record in effectively developing new fields, redeveloping legacy fields, rejuvenating production, controlling unit costs, and adding incremental reserves at attractive finding costs in both onshore and offshore fields.
- *Acquisitions:* In addition to our internal exploration and development activities on our existing properties, we also compete actively for new oil and gas properties through property acquisitions as well as corporate transactions. Our management team has substantial experience identifying and executing a wide variety of tactical and strategic transactions that augment our existing operations or present opportunities to expand into new operating regions. Due to our existing prospect inventory, we are not compelled to make acquisitions in order to grow; however, we expect to continue to pursue acquisitions aggressively on an opportunistic basis as an integral part of our growth strategy.

Our Competitive Strengths

We believe our core resources and strengths include:

Diversity of assets and activities. Our assets and operations are diversified primarily among the Permian Basin, Gulf Coast and the Gulf of Mexico deepwater and shelf. Each of these areas involves distinctly different operational characteristics, as well as different financial and operational risks and rewards. Moreover, within these operating areas we pursue a breadth of exploration, development and acquisition activities, which in turn entail unique risks and rewards. By diversifying our assets both onshore and in the Gulf of Mexico, and pursuing a full range of exploration, development and acquisition activities, we strive to mitigate concentration risk and avoid overdependence on any single activity to facilitate our growth. By maintaining a variety of investment opportunities ranging from high-risk, high-impact projects in the deepwater to relatively low-risk, repeatable projects onshore, we attempt to execute a balanced capital program and attain a more moderate company-wide risk profile while still affording our stockholders the significant potential upside attendant to an active deepwater exploration company.

Large prospect inventory. We believe we have significant potential for growth through the exploration and development of our existing asset base. We are one of the largest leaseholders among independent producers in the Gulf of Mexico. We also are an active participant at MMS lease sales. Furthermore, we have a large and growing asset base onshore that we anticipate is capable of sustaining our current drilling program for a number of years. We believe that our large acreage position makes us less dependent on acquisitions for our growth as compared to companies that have less extensive drilling inventories.

Exploration expertise. Our seasoned team of geoscientists has made significant discoveries in the Gulf of Mexico, achieving a cumulative 62% success rate during the three years ended December 31, 2009. Our geoscientists collectively average almost 30 years of relevant industry experience. We believe our emphasis on exploration allows us a competitive advantage over other companies who are either wholly dependent on acquisitions for growth or only sporadically engage in more limited exploration activities.

Operational control and substantial working interests. As of December 31, 2009, we served as operator of properties representing approximately 86% of our production and had an average 73% working interest in our operated properties. We believe operating our properties gives us a competitive advantage over non-operating interest holders, particularly in a challenging financial environment, since operatorship better allows us to determine the extent and timing of our capital programs, as well as to assert the most direct impact on operating costs.

Extensive seismic library. We have access to recent-vintage, regional 3-D seismic data covering a significant portion of the Gulf of Mexico. We use seismic technology in our exploration program to identify and assess prospects, and in our development program to assess hydrocarbon reservoirs with a goal of

optimizing drilling, workover and recompletion operations. We believe that our investment in 3-D seismic data gives us an advantage over companies with less extensive seismic resources in that we are better able to interpret geological events and stratigraphic trends on a more precise geographical basis utilizing more detailed analytical data.

Subsea tieback expertise. We have accumulated an extensive track record in the use of subsea tieback technology, which enables production from subsea wells to existing third-party infrastructure through subsea flow lines and umbilicals. This technology typically allows us to avoid the significant lead time and capital commitment associated with the fabrication and installation of production platforms or floating production facilities, thereby accelerating our project start ups and reducing our financial exposure. In turn, we believe this lowers the economic thresholds of our target prospects and allows us to exploit reserves that otherwise may be considered non-commercial because of the high cost of stand-alone production facilities.

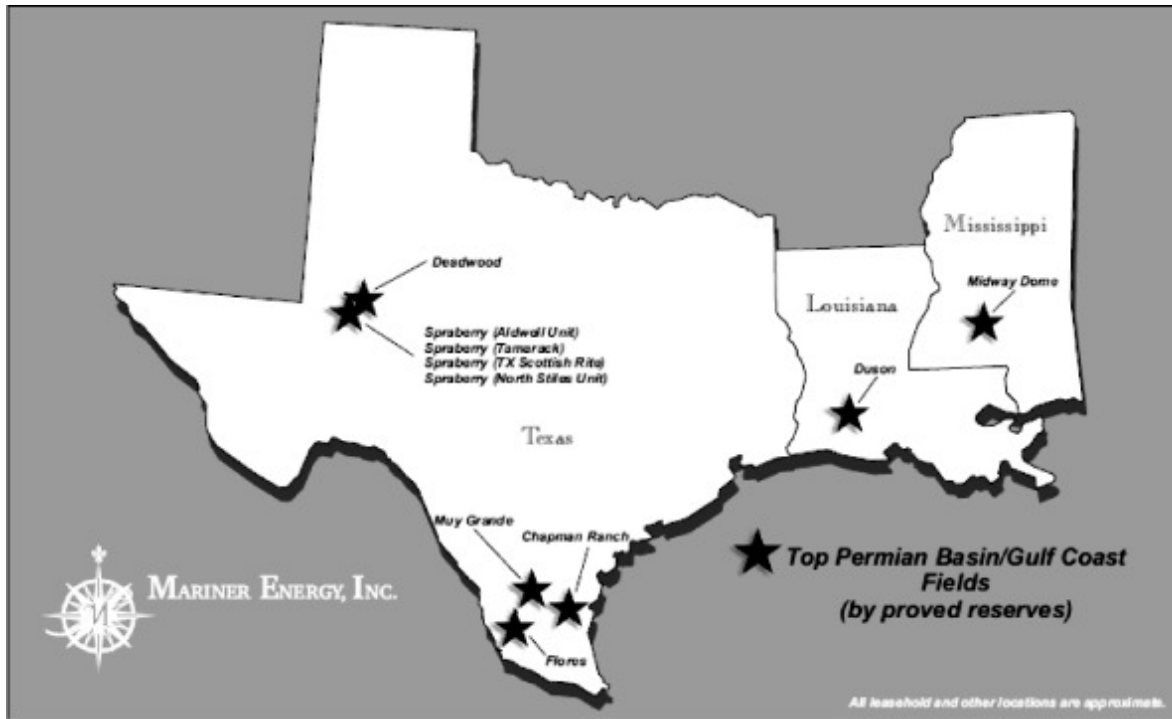
Properties

Our principal oil and gas properties are located in the Permian Basin, Gulf Coast, and the Gulf of Mexico deepwater and shelf. The Gulf of Mexico properties are primarily in federal waters. The following table presents our top fields by estimated proved reserves for each principal geographic area:

	<u>Operator</u>	<u>Approximate Working Interest %</u>	<u>2009 Net Production(2) (Bcfe)</u>	<u>Net Estimated Proved Reserves (Bcfe)</u>	<u>Estimated Proved Reserves % Oil / % Gas(1)</u>
Permian Basin:					
Spraberry (Aldwell Unit)	Mariner	75%	8.0	245.8	66%/34%
Spraberry (Tamarack)	Mariner	93%	4.7	142.3	77%/23%
Spraberry (Texas Scottish Rite Hospital)	Mariner	100%	1.1	43.5	74%/26%
Deadwood	Mariner	73%	0.5	21.9	77%/23%
Spraberry (North Stiles Unit)	Mariner	50%	1.7	14.0	70%/30%
Gulf Coast:					
Flores	Mariner	41%	—	43.9	31%/69%
Chapman Ranch	Mariner	90%	—	11.2	30%/70%
Muy Grande	Mariner	100%	—	7.4	0%/100%
Duson	BTA	44%	—	6.1	22%/78%
Midway Dome	Mariner	89%	—	4.4	16%/84%
Gulf of Mexico Deepwater:					
Atwater Valley 426 (Bass Lite)	Mariner	54%	18.4	77.0	0%/100%
Garden Banks 462 (Geauxpher)	Mariner	60%	13.0	24.1	10%/90%
Green Canyon 646 (Daniel Boone)	W&T Offshore	40%	1.1	19.1	69%/31%
East Breaks 597	Mariner	50%	—	9.9	61%/39%
Ewing Bank 921 (North Black Widow)	ENI	35%	1.8	8.5	93%/7%
Gulf of Mexico Shelf:					
Brazos A19	Mariner	100%	—	38.8	0%/100%
Vermilion 380	Mariner	100%	1.1	33.2	47%/53%
West Cameron 110	Mariner	100%	3.0	24.6	2%/98%
South Pass 24	Mariner	97%	1.5	21.2	59%/41%
South Timbalier 49	Mariner	100%	—	18.2	59%/41%

(1) NGLs are included in Oil

(2) No production results are included for properties of the Edge subsidiaries we acquired on December 31, 2009.



Permian Basin Operations

Our Permian Basin operations historically have emphasized downspacing redevelopment activities in the prolific oil-producing Spraberry field. Since we began our Permian Basin redevelopment initiative in 2002, we have increased by approximately seven-fold our net acreage position and plan continued expansion through our Permian Basin operation's headquarters in Midland, Texas. Production from the region is primarily from the Spraberry, Dean and Wolfcamp formations at depths between 6,000 and 10,000 feet, and is heavily weighted toward long-lived oil and NGLs.

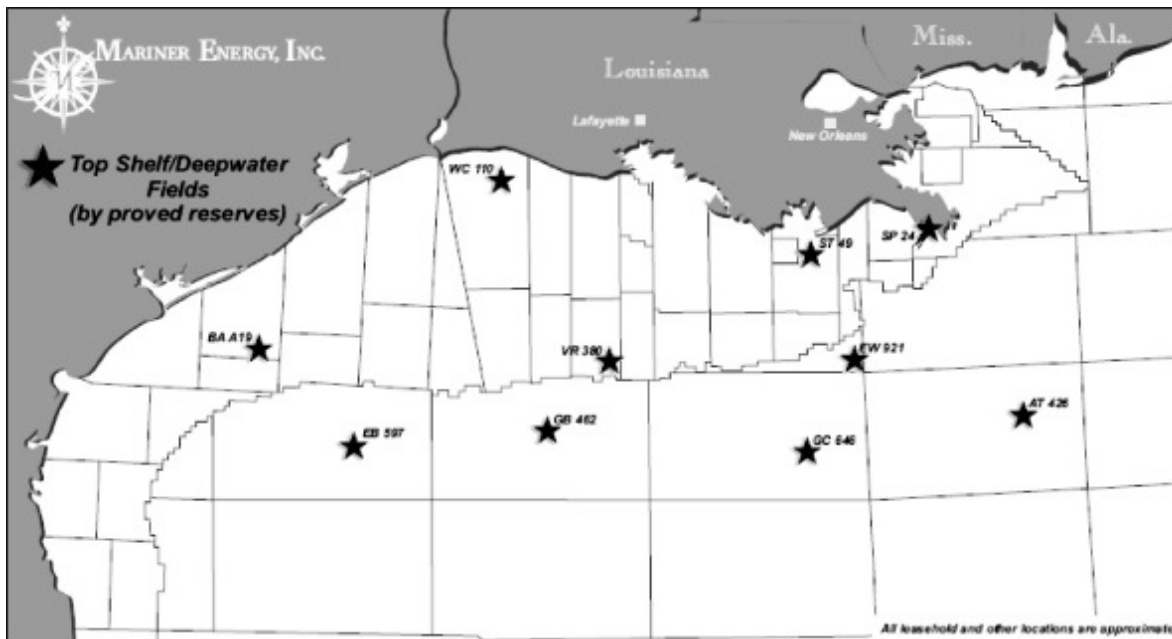
During 2009, our Permian Basin operations produced approximately 18.3 Bcfe (14% of our total production) and accounted for approximately 515.0 Bcfe or 47% of our total estimated proved reserves at year end. Oil and NGLs accounted for 71% of total Permian Basin production for 2009. We drilled 51 wells in the region during 2009, 92% of which were productive. Based upon our current level of drilling activity, our drilling inventory in this area would sustain a five-year drilling program.

Our largest field in the Permian Basin by reserves is the Spraberry Aldwell Unit. We operate our wells in this field and hold an average 75% working interest. At year-end 2009, our share of estimated proved reserves attributed to this field was 245.8 Bcfe, consisting of 66% oil and NGLs and 34% natural gas. Net production for 2009 was 8.0 Bcfe.

The Spraberry Tamarack and Spraberry Texas Scottish Rite Hospital are the next largest fields with 142.3 and 43.5 Bcfe of estimated proved reserves, respectively. The Deadwood field follows with 21.9 Bcfe of estimated proved reserves and the Spraberry North Stiles Unit has estimated proved reserves of 14.0 Bcfe.

Gulf Coast Operations

On December 31, 2009, we acquired interests in 244.0 gross and 98.3 net acres in South Texas, predominantly in the Vicksburg, Queen City and Deep Frio producing trends. As of December 31, 2009, we operated approximately 275 gross wells in this region and had 151 gross non-operated wells.



Gulf of Mexico Deepwater Operations

We have acquired and maintained a significant acreage position in the Gulf of Mexico deepwater. We have successfully generated and operated deepwater exploration and development projects since 1996. As a corollary to our exploration activities, we have pioneered sophisticated deepwater development strategies employing extensive subsea tieback technologies that allow us to produce our discoveries without the expense of permanent production facilities. As of December 31, 2009, we held interests in 99 deepwater blocks and 38 subsea wells. These wells were tied back to 17 host production facilities for production processing. As of December 31, 2009, an additional six projects (Dalmatian, Wide Berth, Balboa, Heidelberg, Lucius and Bushwood) were under development for either tieback to three additional host production facilities or in the case of Heidelberg and Lucius, production from dedicated facilities if warranted by the amount of estimated reserves. Although we have interests throughout the Gulf of Mexico, we focus much of our efforts in infrastructure-dominated corridors where our subsea technology can be most efficiently deployed. We feel our geological understanding based on exploration success in these corridors gives us a competitive advantage in assessing prospects and vying for new leases.

Production in our Gulf of Mexico deepwater operations is largely from Pleistocene to lower Miocene aged formations and varies between oil and gas depending on formation and age. During 2009, our deepwater operations produced approximately 52.8 Bcfe (42% of our total production) and accounted for approximately 161.7 Bcfe or 15% of our total estimated proved reserves at year end. Natural gas accounted for 80% of total deepwater production for 2009. We drilled six wells in the region during 2009, four of which were productive.

We operate Atwater Valley 426, known as Bass Lite, in which we hold a 54% working interest. It is in the Pleistocene formation and is located in approximately 6,600 feet of water. The field consists of two development wells drilled during 2007 that are connected by a 56-mile subsea tieback to the Devil's Tower spar. Limited production on Bass Lite began in February 2008 due to a temporary early production system. The project commenced production at full capacity once the topside facilities work was completed in August 2008 and the field produced 18.4 Bcfe net to our interest during 2009. At year end 2009, our share of estimated proved reserves attributed to this field was 77.0 Bcfe, of which 100% are natural gas.

We operate Garden Banks 462, known as Geauxpher, in which we hold a 60% working interest. We made this deepwater discovery in June 2008. The well, which lies in water depths of approximately 2,800 feet, was drilled to a total depth of 23,156 feet (measured depth). Production on Geauxpher began in May 2009 and the

field produced 13.0 Bcfe net to our interest during 2009. At year-end 2009, our share of estimated proved reserves attributed to the discovery was 24.1 Bcfe, consisting of 10% oil and NGLs and 90% natural gas.

Green Canyon 646, known as Daniel Boone, is operated by W&T Offshore, Inc. and consists of one well in the Pliocene/Pleistocene formation. It is located in approximately 4,200 feet of water and we have an approximate 40% working interest in the well. Production on Daniel Boone began in October 2009 and the field produced 1.1 Bcfe net to our interest during 2009. At year-end 2009, our share of estimated proved reserves attributed to this field was 19.1 Bcfe, consisting of 69% oil and 31% natural gas.

We operate East Breaks 597, known as Balboa, in which we hold a 50% working interest. The well lies in water depths of approximately 3,350 feet and was drilled in July 2001. The well was completed in September 2009 and is awaiting tieback to the Boomvang Spar. Production from Balboa is expected in the second half of 2010. Our share of estimated proved reserves at year-end 2009 was 9.9 Bcfe consisting of approximately 61% oil and 39% natural gas.

Ewing Bank 921, known as North Black Widow, is operated by ENI Petroleum US and began producing in the Pliocene/Pleistocene formation in 2007. We hold an approximate 35% working interest in one well, which is located in approximately 1,700 feet of water. Our share of net production during 2009 was approximately 1.8 Bcfe. At year-end 2009, our share of estimated proved reserves attributed to the field was 8.5 Bcfe, consisting of 93% oil and 7% natural gas.

Gulf of Mexico Shelf Operations

As an operator on the Gulf of Mexico shelf for a number of years, we expanded our Gulf of Mexico shelf operations in 2006 through our acquisition of the Gulf of Mexico operations of Forest Oil Corporation (“Forest”) and in January 2008 through our acquisition of an indirect subsidiary of StatoilHydro ASA that owns substantially all of its former Gulf of Mexico shelf assets and operations. Due to our operational scale and substantial lease position on the shelf, we are able to pursue a diverse array of exploration and development projects on the shelf, including numerous engineering projects designed to increase production and reserves, as well as to manage production costs through optimization of topside facilities and efficiencies of scale. Drilling prospects run the gamut from relatively small, low-risk, conventional shelf projects that can be drilled from one of our numerous existing platform facilities, to high-impact, deep shelf exploration prospects at depths approaching 20,000 total vertical feet.

During 2009, our Gulf of Mexico shelf operation produced approximately 55.4 Bcfe (44% of our total production) and accounted for approximately 315.1 Bcfe or 29% of our total estimated proved reserves at year end. Natural gas accounted for 79% of total shelf production for 2009. We drilled ten wells in the region during 2009, six of which were productive.

Our largest field in the Gulf of Mexico shelf by reserves is Brazos A19. At year-end 2009, estimated proved reserves, all of which are undeveloped, attributed to this field were 38.8 Bcfe, of which 100% is natural gas. This is a recently acquired block and plans are being made to exploit these reserves.

At year-end 2009 estimated proved reserves attributed to our Vermillion 380 field were 33.2 Bcfe, consisting of approximately 47% oil and NGLs and 53% natural gas. During 2008 and 2009, we drilled five wells and added additional production capacity on the “A” platform. Hurricane Ike damaged the structure with the rig on the platform, causing us to suspend drilling while underwater structural repairs were made. We brought the platform back on production at reduced rates until the facilities upgrade was finished. The platform is currently producing approximately 28 MMcfe per day. Our working interest in this block is 100%. Production at Vermillion 380 was approximately 1.1 Bcfe in 2009.

We operate our 100% working interest in West Cameron 110, which consists of six producing wells. We operate the field, which has been producing for more than 20 years from numerous formations in approximately 40 feet of water and produced approximately 3.0 Bcfe net in 2009. At year-end 2009, estimated proved reserves attributed to this field were 24.6 Bcfe, consisting of approximately 2% oil and NGLs and 98% natural gas.

We operate South Pass 24, which consists of 25 producing wells in approximately 10 feet of water. We have a 97% working interest in the property. South Pass 24 has been producing for more than 50 years from numerous formations, and in 2009 produced approximately 1.5 Bcfe net. At year-end 2009, estimated proved reserves attributed to this field were 21.2 Bcfe, consisting of approximately 59% oil and NGLs and 41% natural gas.

We operate South Timbalier 49, in which we hold a 100% working interest. We initiated full production from this field in September 2009. We are producing from the first of many reservoirs encountered in the A-1 well and are currently producing approximately 8 MMcfe per day. At year-end 2009, estimated proved reserves attributed to this field were 18.2 Bcfe (approximately 59% oil and 41% natural gas).

Estimated Proved Reserves

The following tables present certain information with respect to our estimated proved oil and natural gas reserves. The reserve information in the tables below is based on estimates made in fully-engineered reserve reports prepared by Ryder Scott Company, L.P. (except the amount of standardized measure of discounted future net cash flows and information in the table for Sensitivity of Reserves to Prices). Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of the 12-month average price for natural gas and oil calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period to the end of the reporting period and current costs held constant throughout the projected reserve life. Proved reserve estimates do not include any value for probable or possible reserves, which may exist. The proved reserve estimates represent our net revenue interest in our properties.

Summary of Oil and Gas Reserves as of December 31, 2009
Based on Average 2009 Prices

Reserves Category:	Natural gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)
Proved Developed	406.8	31.5	20.1	716.4
Proved Undeveloped	164.6	21.0	13.4	370.7
Total estimated proved oil and gas reserves	571.4	52.5	33.5	1,087.1
PV10 value(1) (\$ in millions):				
Proved developed reserves				\$ 1,350.0
Proved undeveloped reserves				152.2
Total PV10 value(1)				\$ 1,502.2
Standardized measure of discounted future net cash flows				\$ 1,468.4
Twelve-month average prices used in calculating proved reserve measures (excluding effects of hedging):				
Natural gas (\$/MMBtu)				\$ 3.87
Oil (\$/Bbl)				\$ 61.18

Sensitivity of Reserves to Prices

By Principal Product Type and Price Scenario

	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)
Proved oil and natural gas reserves:			
10% Increase in Price	576.9	53.0	33.9
10% Decrease in Price	565.7	51.8	32.9

The following table sets forth certain information with respect to our estimated proved reserves by geographic area as of December 31, 2009 based on estimates made in a reserve report prepared by Ryder Scott Company, L.P.

Geographic Area	Estimated Proved Developed Reserve Quantities				Estimated Proved Undeveloped Reserve Quantities				Estimated Proved Reserve Quantities
	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Total (Bcfe)
Permian Basin	84.7	16.4	15.7	277.1	63.9	16.7	12.3	237.9	515.0
Gulf Coast	43.2	0.7	2.0	59.5	16.3	0.2	0.8	22.1	81.6
Gulf of Mexico Deepwater	111.5	3.5	0.5	135.7	9.3	2.8	—	26.0	161.7
Gulf of Mexico Shelf	160.2	10.3	1.9	233.2	72.9	1.2	0.3	81.9	315.1
Other onshore	7.2	0.6	—	10.9	2.2	0.1	—	2.8	13.7
Total	406.8	31.5	20.1	716.4	164.6	21.0	13.4	370.7	1,087.1

Geographic Area	PV10 Value(1)			Standardized Measure (In millions)
	Developed	Undeveloped (In millions)	Total	
Permian Basin	\$ 440.8	\$ 51.6	\$ 492.4	
Gulf Coast	103.8	9.8	113.6	
Gulf of Mexico Deepwater	324.8	54.7	379.5	
Gulf of Mexico Shelf	458.0	33.0	491.0	
Other onshore	22.6	3.1	25.7	
Total	\$ 1,350.0	\$ 152.2	\$ 1,502.2	\$ 1,468.4

(1) PV10 value (“PV10”) is not a measure under generally accepted accounting principles in the United States of America (“GAAP”) and differs from the corollary GAAP measure “standardized measure of discounted future net cash flows” or “standardized measure” in that PV10 is calculated without regard to future income taxes. Management believes that the presentation of PV10 values is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our estimated proved reserves independent of our individual income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to our reserves. 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. For these reasons, management uses, and believes the industry generally uses, the PV10 measure in evaluating and comparing acquisition candidates and assessing the potential return on investment related to investments in oil and natural gas properties.

PV10 is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. For our presentation of the standardized measure of discounted future net cash flows, please see Note 16 “Supplemental Oil and Gas Reserve and Standardized Measure Information” in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this Annual Report on Form 10-K. The table below provides a reconciliation of PV10 to standardized measure of discounted future net cash flows.

Non-GAAP Reconciliation:	Year Ended December 31,		
	2009	2008 (In millions)	2007
Present value of estimated future net revenues (PV10)	\$ 1,502.2	\$ 1,667.5	\$ 3,064.2
Future income taxes, discounted at 10%	(33.8)	(184.5)	(832.3)
Standardized measure of discounted future net cash flows	\$ 1,468.4	\$ 1,483.0	\$ 2,231.9

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural 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 and operating costs, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates.

A combination of technologies is used in estimating our proved reserves. Approximately 60% of our proved reserves as of December 31, 2009 were estimated using the performance method and the balance were estimated using the volumetric method. A combination of geological structural and isochore maps, well logs, core analyses, and pressure measurements support the reserves estimates. In general, reserves attributable to producing wells or reservoirs were estimated by performance methods such as decline curve analysis, material balance or reservoir simulation which used extrapolations of historical production and pressure data available through December 2009. In certain cases, producing reserves were more appropriately estimated by the

volumetric method, such as when there was inadequate historical performance data to establish a definitive trend. Certain reserves attributable to non-producing and undeveloped reservoirs were estimated by the volumetric method using pertinent well and seismic data available through December 31, 2009.

The process of estimating reserves is complex and requires many assumptions as discussed below in “Item 1A. Risk Factors.” As a result, we have developed internal controls for estimating and recording reserves. These controls require reserves to be in compliance with SEC definitions and guidance. Our controls assign responsibility for compliance in reserves bookings to our reservoir engineering team. Annual estimates of our proved reserves and future production and income attributable to those reserves are prepared using the economic software package Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. Our reservoir engineering team coordinates with our land, marketing and accounting departments and those of our executive officers responsible for given operating areas in reconciling year-over-year reserve changes for each of our fields. These efforts are designed to help ensure that our database reflects information pertaining to performance revisions, production, drilling, acquisitions, sales, recompletions, wells, working interests, net revenue interests, lease operating expenses, taxes, capital costs and PV10 of future net revenues. Our reservoir engineering team certifies this information to a third-party independent reservoir engineering firm in connection with its preparation of our proved reserve estimates. Our Chief Operating Officer reviews the third-party firm’s estimates of our proved reserves and ultimately certifies our acceptance of those estimates. These estimates also are presented to our board of directors in connection with its consideration of our annual report on Form 10-K.

Our reservoir engineering team is led by Richard A. Molohon, Vice President — Reservoir Engineering. He is the technical person primarily responsible internally for overseeing the preparation of our reserves estimates by Ryder Scott Company, L.P. Mr. Molohon has been a Registered Professional Engineer in Texas since 1983, joined us as a Senior Reservoir Engineer in 1995 and is a member of the Society of Petroleum Engineers. For addition information on Mr. Molohon’s background, see “Executive Officers” below under Item 4. Mr. Molohon reports to our Chief Operating Officer who reports to our Chairman, Chief Executive Officer and President. No portion of the compensation of our management or the reservoir engineering team is directly dependent on the quantity of reserves booked.

We engage Ryder Scott Company, L.P. to prepare 100% of our proved reserves estimates. The technical person at Ryder Scott Company, L.P. primarily responsible for overseeing the preparation of our reserves estimates is Edward J. Gibbon, a Senior Vice President of Ryder Scott Company, L.P. Mr. Gibbon earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1968 and is a Licensed Professional Engineer in the State of Texas and a Registered Professional Engineer in the State of Louisiana. He also is a member of the Society of Petroleum Evaluation Engineers, the Society of Petroleum Engineers, and the Society of Petrophysicists and Well Log Analysts. Additional information on Mr. Gibbon’s background is contained in the report of Ryder Scott Company, L.P. filed as an exhibit to this Annual Report on Form 10-K. Mr. Gibbon meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Proved Undeveloped Reserves

As of December 31, 2009, our estimated proved undeveloped reserves (“PUDs”) totaled 370.7 Bcfe or 34.0% of our total estimated proved reserves and consisted of 164.6 Bcf of gas, 21.0 MMBbls of oil and 13.4 MMBbls of NGLs. Approximately 64.2% of these PUDs were in the Permian Basin, 22.1% were in the Gulf of Mexico shelf, 7.0% were in the Gulf of Mexico deepwater, 6.0% were in the Gulf Coast and 0.7% were in other onshore properties.

During 2009, we converted approximately 49.7 Bcfe or 16.8% of our total PUDs as of December 31, 2008 to proved developed reserves as of December 31, 2009, of which approximately 79.9%, 13.3% and 6.8% were in the Gulf of Mexico shelf, Gulf of Mexico deepwater and Permian Basin, respectively. We also developed approximately 7.7 Bcfe during 2009 that were estimated proved developed reserves in the Permian

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Basin at December 31, 2009 but were not included in our year-end 2008 proved reserves. We spent approximately \$125.8 million during 2009 on development activities to convert PUDs to proved developed reserves. At December 31, 2009, we eliminated approximately 39.7 Bcfe or 13.4% of our total PUDs as of December 31, 2008, of which approximately 56.9%, 23.9% and 19.2% were in the Gulf of Mexico shelf, Permian Basin and Gulf of Mexico deepwater, respectively, primarily due to pricing (59.1% of the total eliminated) and performance (40.9% of the total eliminated) considerations.

Of our total 370.7 Bcfe of PUDs as of December 31, 2009, approximately 20.2 Bcfe or 5.4% remained undeveloped for more than five years. Of the 20.2 Bcfe, approximately 62.2% were in the Gulf of Mexico deepwater awaiting expected conversion to proved developed reserves upon a side track updip after the current wellbore depletes, and the balance were in the Spraberry (Aldwell Unit) field in the Permian Basin where we have been drilling continuously since 2002.

The following tables present our natural gas, oil and NGL production and revenue, excluding the effects of hedging, by area for the indicated periods. The tables excludes the properties of the Edge subsidiaries we acquired on December 31, 2009.

	Year Ended December 31,		
	2009	2008	2007
Production			
Permian Basin:			
Natural gas (Bcf)	5.0	4.0	3.7
Oil (MBbls)	1,468.0	1,242.8	861.2
NGLs (MBbls)	744.0	578.5	387.3
Total Natural Gas Equivalent (Bcfe)	18.3	14.9	11.2
Gulf of Mexico Deepwater:			
Natural gas (Bcf)	42.1	27.7	14.7
Oil (MBbls)	1,427.0	1,850.5	1,301.9
NGLs (MBbls)	362.2	264.7	126.2
Total Natural Gas Equivalent (Bcfe)	52.8	40.4	23.3
Gulf of Mexico Shelf:			
Natural gas (Bcf)	43.7	48.1	49.4
Oil (MBbls)	1,576.5	1,787.7	2,050.3
NGLs (MBbls)	371.7	714.7	686.3
Total Natural Gas Equivalent (Bcfe)	55.4	63.1	65.8
Total Production:			
Natural gas (Bcf)	90.8	79.8	67.8
Oil (MBbls)	4,471.5	4,881.0	4,213.4
NGLs (MBbls)	1,477.9	1,557.9	1,199.8
Total Natural Gas Equivalent (Bcfe)	126.5	118.4	100.3

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Revenue (excluding the effects of hedges)			
Permian Basin:			
Natural gas	\$ 19,775	\$ 31,339	\$ 25,153
Oil	87,153	122,005	61,528
NGLs	23,794	30,765	17,871
Total	\$ 130,722	\$ 184,109	\$ 104,552
Gulf of Mexico Deepwater:			
Natural gas	\$ 168,564	\$ 271,979	\$ 104,840
Oil	86,524	180,131	90,631
NGLs	12,611	15,053	5,538
Total	\$ 267,699	\$ 467,163	\$ 201,009
Gulf of Mexico Shelf:			
Natural gas	\$ 176,063	\$ 467,099	\$ 346,078
Oil	97,164	190,504	145,634
NGLs	12,516	39,897	30,783
Total	\$ 285,743	\$ 697,500	\$ 522,495
Total Revenues:			
Natural gas	\$ 364,402	\$ 770,417	\$ 476,071
Oil	270,841	492,640	297,793
NGLs	48,921	85,715	54,192
Total	\$ 684,164	\$ 1,348,772	\$ 828,056

Average Sales Prices and Production Costs

The following table presents our average realized sales prices and average production costs for the indicated periods. The table does not include operating results of the subsidiaries we acquired from Edge on December 31, 2009.

	Year Ended December 31,		
	2009	2008	2007
Average realized sales prices:			
Natural gas (per Mcf)	\$ 6.08	\$ 9.31	\$ 7.88
Oil (per Bbl)	70.59	86.02	67.50
Natural gas liquids (per Bbl)	33.10	55.02	45.16
Total natural gas equivalent (\$/Mcfe)	7.25	10.54	8.71
Average realized sales prices excluding the effects of hedging:			
Natural gas (per Mcf)	\$ 4.01	\$ 9.66	\$ 7.02
Oil (per Bbl)	60.57	100.93	70.68
Natural gas liquids (per Bbl)	33.10	55.02	45.16
Total natural gas equivalent (\$/Mcfe)	5.41	11.39	8.26
Average production costs per Mcfe:	\$ 1.97	\$ 1.96	\$ 1.52

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2009 and December 31, 2008.

	Year Ended December 31,			
	2009		2008	
	Gross	Net	Gross	Net
Oil	1,037.0	792.0	936.0	733.0
Natural gas	380.0	213.8	154.0	90.2
Total	1,417.0	1,005.8	1,090.0	823.2

Acreage

The following table sets forth certain information with respect to actual developed and undeveloped acreage in which we own an interest as of December 31, 2009.

	Year Ended December 31, 2009					
	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	103,507	81,861	165,894	66,256	269,401	148,117
Gulf Coast	64,229	27,273	37,689	19,967	101,918	47,240
Gulf of Mexico Deepwater	87,757	39,610	432,691	226,386	520,448	265,996
Gulf of Mexico Shelf	697,131	383,911	313,684	228,936	1,010,815	612,847
Other Onshore	19,800	7,984	104,511	81,145	124,311	89,129
Total	972,424	540,639	1,054,469	622,690	2,026,893	1,163,329

The following table sets forth that portion of our onshore and offshore undeveloped acreage as of December 31, 2009 that is subject to expiration absent drilling activity during the three years ended December 31, 2012 and thereafter.

	Undeveloped Acreage Subject to Expiration in the Year Ended December 31,							
	2010		2011		2012		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian Basin	22,735	16,950	29,653	27,229	3,526	3,450	49,840	17,943
Gulf Coast	22,460	19,505	17,256	13,164	224	516	7,200	3,612
Gulf of Mexico Deepwater	57,600	17,856	34,560	17,280	34,560	4,212	305,971	186,930
Gulf of Mexico Shelf	32,665	22,864	101,336	73,508	32,454	25,150	147,229	107,414
Other Onshore	32,370	25,884	6,087	5,472	1,765	1,424	921	513
Total	167,830	103,059	188,892	136,653	72,529	34,752	511,161	316,412

Drilling Activity

Certain information with regard to the number of wells drilled during the years ended December 31, 2009, 2008 and 2007 is set forth below. The number of wells drilled refers to the number of wells completed at any time during a given year, regardless of when drilling was initiated. The following table does not include any drilling activity of the Edge subsidiaries we acquired on December 31, 2009.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	10.00	5.97	15.00	8.59	11.00	5.96
Dry	10.00	7.00	5.00	2.98	8.00	4.91
Total	20.00	12.97	20.00	11.57	19.00	10.87
Development wells:						
Productive	33.00	30.08	125.00	88.93	121.00	60.43
Dry	—	—	—	—	—	—
Total	33.00	30.08	125.00	88.93	121.00	60.43
Extension wells:						
Productive	14.00	9.49	3.00	3.00	—	—
Dry	—	—	—	—	—	—
Total	14.00	9.49	3.00	3.00	—	—
Total wells:						
Productive	57.00	45.54	143.00	100.52	132.00	66.39
Dry	10.00	7.00	5.00	2.98	8.00	4.91
Total	67.00	52.54	148.00	103.50	140.00	71.30

As of February 22, 2010, the following wells were drilling:

Well Name	Operator	Approximate Working Interest	Location	Gross	Net
West Cameron 112 A-2	Mariner	55%	Shelf	1.00	0.55
South Marsh 11 #58	Mariner	100%	Shelf	1.00	1.00
Green Canyon 903 #1	Anadarko	13%	Deepwater	1.00	0.13
Cathey 2906 #1	Mariner	61%	Permian Basin	1.00	0.61
SRH 1609	Mariner	100%	Permian Basin	1.00	1.00
Keathley 46 #2	Mariner	100%	Permian Basin	1.00	1.00
Currie 23 #1	Mariner	50%	Permian Basin	1.00	0.50
SRH 1705	Mariner	100%	Permian Basin	1.00	1.00
Cowden E #5	Mariner	55%	Permian Basin	1.00	0.55

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. Our natural gas, oil and NGLs production is sold to a variety of customers under short-term marketing arrangements at market-based

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prices. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

Customer	Percentage of Total Revenues for Year Ended December 31,		
	2009	2008	2007
Williams Gas and affiliates	12%	5%	<1%
ChevronTexaco and affiliates	13%	16%	23%
Plains Marketing LP	11%	5%	7%
Shell	9%	10%	10%

Title to Properties

Substantially all of our properties currently are subject to liens securing our bank credit facility and obligations under hedging arrangements with lenders under our bank credit facility. 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 interfere 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 performed customary investigation of, and 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 are less likely to arise with offshore oil and natural gas properties than with onshore properties.

Competition

We believe that our leasehold acreage, exploration, drilling and production capabilities, large 3-D seismic database and technical and operational experience enable us to compete effectively. However, our primary competitors include major integrated oil and natural gas companies, nationally owned or sponsored enterprises, and domestic 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 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 ("RRA"), effective November 28, 1995, provides that all tracts in the Western and Central Planning Areas of the Gulf of Mexico, including whole lease blocks in the Eastern Planning Area of the Gulf of Mexico lying west of 87 degrees, 30 minutes West

longitude, in water more than 200 meters deep and offered for bid within five years after the effective date of the RRA, will be entitled to royalty relief as follows:

Water Depth	Royalty Relief
200-400 meters	no royalty payable on the first 17.5 million BOE produced
400-800 meters	no royalty payable on the first 52.5 million BOE produced
800 meters or deeper	no royalty payable on the first 87.5 million BOE produced

Leases offered for bid within five years after the effective date of the RRA are referred to as “post-Act leases.” The RRA also allows federal offshore lessees the opportunity to apply for discretionary royalty relief for new production on leases acquired before the RRA was enacted, or “pre-Act leases.” If the MMS determines that new production under a pre-Act lease would not be economic without royalty relief, then the MMS may relieve a portion of the royalty to make the project economic.

In addition to granting discretionary royalty relief, the MMS has elected to include royalty relief provisions in many leases issued after November 28, 2000, or “post-2000 leases.” For these post-2000 lease sales that have occurred to-date for which the MMS has elected to include royalty relief, 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 natural gas produced in water depths of less than 200 meters and from deep natural gas accumulations of at least 15,000 feet of true vertical depth. Drilling of qualified wells must have started on or after March 26, 2003, and production must begin before May 3, 2009, unless the lessee obtains a one-year extension. These incentives generally apply only to production that occurs during years when the average price of natural gas on the New York Mercantile Exchange does not exceed the price threshold of \$10.15 per million Btu, expressed in 2007 dollars. In regulations published in November 2008, the MMS implemented additional royalty relief provisions to reflect statutory changes enacted in the Energy Policy Act of 2005. The regulations provide enhanced incentives for gas production from wells of at least 20,000 feet of true vertical depth in waters of 400 meters or less. These regulations also expand the royalty relief incentives for natural gas produced from leases in waters 200 to 400 meters deep by entitling such leases to the royalty relief incentives available under the existing regulations for leases in less than 200 meters of water, with two exceptions. First, the incentive for production in waters 200 to 400 meters in depth applies to wells for which drilling began on or after May 18, 2007, rather than March 26, 2003, and that begin production before May 3, 2013, rather than May 3, 2009. Second, the applicable price threshold is \$4.55 per million Btu, expressed in 2007 dollars, rather than \$10.15.

The impact of royalty relief can be significant. Effective with lease sales in 2008, royalty rates for leases in all water depths in the Gulf of Mexico increased to 18.75% of production. For Gulf of Mexico leases awarded in 2007 lease sales, the royalty rate was 16.7% of production in all water depths. Royalty relief can substantially improve the economics of projects located in deepwater or in shallow water involving deep natural gas.

Many of our MMS leases that are subject to royalty relief contain language that suspends 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 remaining below the price threshold specified for that year. Since 2000, commodity prices have exceeded some of the predetermined price thresholds, except in 2002, for a number of our projects. For the affected leases, we were ordered by the MMS to pay royalties for natural gas produced in some of those years. However, we challenged the MMS’s authority to include price thresholds in six of our post-Act leases awarded in 1996 and 1997 because we believe that post-Act leases are entitled to automatic royalty relief under the RRA, regardless of commodity prices. In February 2010, the MMS withdrew its orders in respect of these leases, closing the matter in our favor. For more information, see “Item 3. Legal Proceedings.”

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 and Crude Oil

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 and at just and reasonable rates 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.

The FERC also regulates interstate crude oil pipeline transportation rates and service conditions under the Interstate Commerce Act, which affect the marketing of crude oil produced by us and the revenues received by us for sales of such oil. The FERC requires interstate pipelines to provide non-discriminatory, common

carrier service at just and reasonable rates. The intra-state transportation of crude oil is subject to state regulatory jurisdiction. FERC and the state agencies modify their transportation policies and regulations from time to time. Also, in the Energy Policy Act of 2007, Congress directed the Federal Trade Commission to impose regulations prohibiting deceptive or manipulative practices relating to the sale of crude oil. In 2009, the FTC issued a rule similar to FERC's anti-manipulation rule for gas.

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.

Our crude oil and gas production is subject to royalty interests established under the applicable leases. Royalty on production from state and private leases is generally governed by state law and royalty on production from leases on federal or Indian lands is governed by federal law. The MMS is authorized by statute to administer royalty valuation and collection for production from federal and Indian leases. The MMS generally exercises this authority through standards established under its regulations and related policies. We do not anticipate that we will be affected by changes in federal or state law affecting royalty obligations any differently than other producers of crude oil and natural gas.

Environmental and Safety 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.

The following is a summary of some of the existing laws and regulations to which our business operations are subject:

Spills and Releases. The Comprehensive Environmental Response, Compensation, and Liability Act (“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 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 (“OPA”). 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 United States. 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 \$75.0 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 \$35.0 million to cover liabilities related to an oil spill. The amount of financial assurance required under the OPA may be increased up to \$150.0 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 waters. The Clean Water Act provides for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants, and imposes liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. Comparable state statutes impose liabilities and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other pollutants, into state waters.

In furtherance of the Clean Water Act, the Environmental Protection Agency ("EPA") promulgated the Spill Prevention, Control, and Countermeasure ("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 required compliance with the implementation of such amended plans by August 18, 2006. This compliance deadline has been extended multiple times and on May 16, 2007 was extended until July 1, 2009. We have SPCC plans and similar contingency plans in place at several of our facilities, and may be required to prepare such plans for additional facilities where a spill or release of oil could reach or impact jurisdictional waters of the United States. We do not anticipate that the revisions to the SPCC regulations will cause a material impact on our operations or financial condition.

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. Except as outlined below regarding climate change issues, 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.

Climate Change. There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of emissions of greenhouse gases ("GHG"), in particular from the combustion of fossil fuels. Under the Clean Air Act and various state analogues, regulations limiting GHG emissions or imposing reporting obligations with respect to such emissions have been proposed or finalized. On October 30, 2009, EPA published a final rule requiring the reporting of GHG emissions from specified large sources in the United States beginning in 2011 for emissions occurring in 2010. In addition, on December 15, 2009, EPA published a Final Rule finding that current and projected concentrations of six key GHGs in the atmosphere threaten public health and welfare of current and future generations. EPA also found that the combined emissions of these GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG pollution that threatens public health and welfare. This Final Rule, also known as EPA's Endangerment Finding, does not impose any requirements on industry or other entities directly; however, after the rule's January 14, 2010 effective date, EPA will be able to finalize motor vehicle GHG standards, the effect of which could reduce demand for motor fuels refined from crude oil. Finally, according to EPA, the final motor vehicle GHG standards will trigger construction and operating permit requirements for stationary sources. As a result, EPA has proposed to tailor these programs such that only stationary sources, including refineries, that emit over 25,000 tons of GHGs per year will be subject to air permitting requirements. In addition, on September 22, 2009, EPA issued a "Mandatory Reporting of Greenhouse Gases" final rule ("Reporting Rule").

The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. Further, proposed legislation has been introduced in Congress that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. Any limitation on emissions of GHGs from our equipment or operations could require us to incur costs to reduce such emissions. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our operations, results of operations, and cash flows. Moreover, incentives to conserve or use alternative energy sources could reduce demand for fossil fuels, resulting in a decrease in demand for our products.

Climate change also poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make estimating any future financial risk to our operations caused by these physical risks of climate change extremely challenging.

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

Endangered Species Act. The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. We believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Safety. The Occupational Safety and Health Act, or OSHA, and other similar laws and regulations govern the protection of the health and safety of employees. The OSHA hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA and analogous state statutes require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governments and citizens. We believe that we are in substantial compliance with these requirements and with other applicable OSHA requirements.

Employees

As of December 31, 2009, we had 328 full-time employees. Our employees are not represented by any labor unions. We have never experienced a work stoppage or strike and we consider relations with our employees to be satisfactory.

Insurance Matters

Current Insurance Against Hurricanes

Mariner is a member of OIL Insurance Limited (“OIL”), an energy industry insurance cooperative, which provides Mariner windstorm insurance coverage. During 2009, the coverage was subject to a \$10.0 million per-occurrence deductible, a \$250.0 million per-occurrence loss limit, and a \$750.0 million industry aggregate per-event loss limit. Effective January 1, 2010, the coverage is subject to a per-occurrence deductible which remains under consideration, a \$150.0 million per-occurrence loss limit per member, an annual maximum of \$300.0 million per member, and a \$750.0 million industry aggregate per-event loss limit. In addition, annual industry windstorm losses exceeding \$300.0 million will be mutualized among windstorm members in two pools, one for offshore and one for onshore, with future premiums based upon a pool’s loss experience and a member’s weighted percent of the pool’s asset base. Mariner anticipates these changes to increase its loss retention by approximately \$100.0 million for windstorm losses, which it expects to either self insure, insure through the commercial market, insure through the purchase of additional OIL coverage or a combination of these.

Each year, Mariner considers whether to purchase from the commercial market supplemental or excess insurance which in the past has provided coverage when OIL limits have been exceeded (see discussion below under “— Hurricanes Katrina and Rita (2005)”). The supplemental insurance coverage offered by the commercial market in 2009 would not have provided similar coverage and Mariner elected not to purchase it when it expired on June 1, 2009. Mariner believes its assets are sufficiently insured through OIL and Mariner’s expected ability to cover losses in excess of OIL coverage. Mariner intends to monitor the commercial market for insurance that would, based on Mariner’s historical experience, cover its expected hurricane-related risks on a cost-effective basis once OIL limits are exceeded.

As of December 31, 2009, Mariner accrued approximately \$48.0 million for an OIL withdrawal premium contingency. As part of its OIL membership, Mariner is obligated to pay a withdrawal premium if it elects to withdraw from OIL. Mariner does not anticipate withdrawing from OIL; however, due to the contingency, Mariner periodically reassesses the sufficiency of its accrued withdrawal premium based on OIL’s periodic calculation of the potential withdrawal premium in light of past losses, and Mariner may adjust its accrual accordingly in the future. OIL requires smaller members to provide a letter of credit or other acceptable security in favor of OIL to secure payment of the withdrawal premium. Acceptable security has included a letter of credit or a security agreement pursuant to which a member grants OIL a security interest in certain claim proceeds payable by OIL to the member. Mariner has entered into such a security agreement, granting to OIL a senior security interest in up to the next \$50.0 million in excess of \$100.0 million of Mariner’s Hurricane Ike claim proceeds payable by OIL. Mariner has the ability to replace the security agreement with a letter of credit or other acceptable security in favor of OIL.

Hurricane Ike (2008)

In 2008, Mariner’s operations were adversely affected by Hurricane Ike. The hurricane resulted in shut-in and delayed production as well as facility repairs and replacement expenses. Mariner estimates that repairs and plugging and abandonment costs resulting from Hurricane Ike will total approximately \$160.0 million net to Mariner’s interest. OIL has advised Mariner that industry-wide damages from Hurricane Ike are expected to substantially exceed OIL’s \$750.0 million industry aggregate per event loss limit and that OIL expects to initially prorate the payout of all OIL members’ Hurricane Ike claims at approximately 50%, subject to further adjustment. OIL also has indicated that the scaling factor it expects to apply to Mariner’s Hurricane Ike claims will result in settlement at less than 70%. Mariner expects that approximately 75% of the shortfall in its primary insurance coverage will be covered under its commercial excess coverage. In respect of Hurricane Ike

claims that Mariner made through December 2009, it received approximately \$30.6 million from OIL and \$9.7 million from excess carriers. Although in 2009 Mariner started receiving payment in respect of its Hurricane Ike claims, due to the magnitude of the storm and the complexity of the insurance claims being processed by the insurance industry, Mariner expects to maintain a potentially significant insurance receivable through 2010 while it actively pursues settlement.

Hurricanes Katrina and Rita (2005)

In 2005, Mariner's operations were adversely affected by Hurricanes Katrina and Rita, resulting in substantial shut-in and delayed production, as well as necessitating extensive facility repairs and hurricane-related abandonment operations. Since 2005, Mariner has incurred approximately \$208.6 million in hurricane expenditures resulting from Hurricanes Katrina and Rita, of which \$130.6 million were capitalized expenditures and \$78.0 million were hurricane-related abandonment costs.

Applicable insurance for Mariner's Hurricane Katrina and Rita claims with respect to the Gulf of Mexico assets acquired in March 2006 was provided by OIL. Mariner's coverage for such properties was subject to a deductible of \$5.0 million per occurrence and a \$1.0 billion industry-wide loss limit per occurrence. OIL advised Mariner that the aggregate claims resulting from each of Hurricanes Katrina and Rita were expected to exceed the \$1.0 billion per occurrence loss limit and that therefore Mariner's insurance recovery was expected to be reduced pro-rata (approximately 47% for Katrina and 67% for Rita) with all other competing claims from the storms. During 2008, Mariner settled its Katrina and Rita claims with its excess insurers for a one-time cash payment of \$48.5 million.

As of December 31, 2009, Mariner had recovered approximately \$137.0 million in respect of Hurricanes Katrina and Rita, of which \$88.5 million was paid by OIL and \$48.5 million was paid by excess insurers. Although Mariner has received full and final settlement of its insurance claims in respect of Hurricanes Katrina and Rita as of December 31, 2009, it may receive from OIL a relatively immaterial additional amount in respect of Hurricane Rita after OIL finally adjusts all of its members' Hurricane Rita claims.

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and natural gas industry terms used in this annual report.

3-D seismic data. (Three-Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional seismic data.

Acquisition of properties. Cost incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers fees, recoding fees, legal costs, and other costs incurred in acquiring properties.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(2) of Regulation S-X.

Appraisal well. A well drilled several spacing locations away from a producing well to determine the boundaries or extent of a productive formation and to establish the existence of additional reserves.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the MMS or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for production of oil or gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Conventional shelf well. A well drilled on the outer continental shelf to subsurface depths above 15,000 feet.

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths below 15,000 feet.

Deepwater. Depths greater than 1,300 feet (the approximate depth of deepwater designation by the MMS, on December 31, 2009).

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed reserves. Reserves of any category that can be expected to be recovered. This definition has been abbreviated from the definition of “Developed oil and gas reserves” contained in Rule 4-10(a)(6) of Regulation S-X.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(7) of Regulation S-X.

Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Dry well costs. Costs incurred in drilling a well, assuming a well is not productive, including plugging and abandonment costs.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(10) of Regulation S-X.

Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of

drilling exploratory wells and exploratory-type stratigraphic test wells. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(12) of Regulation S-X.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this glossary.

Extension well. A well drilled to extend the limits of a known reservoir.

Farm-in or farm-out. An agreement under which the owner of a working interest in an oil or gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in” while the interest transferred by the assignor is a “farm-out.”

Field. An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(15) of Regulation S-X.

Gas. Natural gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned. A gross acre or well is an acre or well in which a working interest is owned.

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

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMBbls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

MMS. Minerals Management Service of the United States Department of the Interior.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells. A net acre or well is deemed to exist when the sum of fractional ownership working interests in gross acres or wells equals one.

Net revenue interest. An interest in all oil and natural gas produced and saved from, or attributable to, a particular property, net of all royalties, overriding royalties, net profits interests, carried interests, reversionary interests and any other burdens to which the person's interest is subject.

Oil. Crude oil. Unless otherwise stated, references to oil include condensate.

Operator. The individual or company responsible for the exploration and/or exploitation and/or production of an oil or gas well or lease.

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

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(17) of Regulation S-X.

Present value of estimated future net revenues or PV10. An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC's practice, to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(18) of Regulation S-X.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(20) of Regulation S-X.

Productive well. An exploratory, development or extension well that is not a dry well. Productive wells include producing wells and wells mechanically capable of production.

Prospect. A specific geographic area, which based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Proved developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of crude oil and gas, which, by analysis of that geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. This definition has been abbreviated from the definition of "Proved oil and gas reserves" contained in Rule 4-10(a)(22) of Regulation S-X.

Recompletion. The completion for production in an existing well bore to another formation from that which the well has been previously completed.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. This definition abbreviated from the applicable definition contained in Rule 4-10(a)(26) of Regulation S-X.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Shelf. Areas in the Gulf of Mexico with depths less than 1,300 feet. Our shelf area and operations also includes a small amount of properties and operations in the onshore and bay areas of the Gulf Coast.

Standardized measure of discounted future net cash flows. The standardized measure represents value-based information about an enterprise's proved oil and gas reserves based on estimates of future cash flows, including income taxes, from production of proved reserves assuming continuation of year-end economic and operating conditions.

Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geological condition. The classification also includes test identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

Subsea tieback. A method of completing a productive well by connecting its wellhead equipment located on the sea floor by means of control umbilical and flow lines to an existing production platform located in the vicinity.

Subsea trees. Wellhead equipment installed on the ocean floor.

Tcfe. Trillion cubic feet equivalent of natural gas.

Undeveloped acreage. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

Undeveloped reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. This definition has been abbreviated from the definition of "Undeveloped oil and gas reserves" contained in Rule 4-10(a)(31) of Regulation S-X.

Unproved properties. Properties with no proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Item 1A. Risk Factors.

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 increased to, and then declined significantly from, historical highs in 2008 and may fluctuate and decline significantly in the 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. To the extent that oil or natural gas comprises more than 50% of our production or estimated proved reserves, our financial results may be more sensitive to movements in prices of that commodity. 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. See above “Item 1. Business — Estimated Proved Reserves.” In addition, we may, from time to time, enter into long-term contracts based upon our reasoned expectations for commodity price levels. If commodity prices subsequently decrease significantly for a sustained period, we may be unable to perform our obligations or otherwise breach the contract and be liable for damages.

The recent worldwide financial and credit crisis could lead to an extended worldwide economic recession and have a material adverse effect on our results of operations and liquidity.

The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A recession or slowdown in economic activity would likely reduce worldwide demand for energy and result in lower oil and natural gas prices, which could materially adversely affect our profitability and results of operations.

In addition, the economic crisis may adversely affect our liquidity. We may be unable to obtain adequate funding under our bank credit facility because our lending counterparties may be unwilling or unable to meet their funding obligations, or because our borrowing base under the facility may be decreased as the result of a redetermination, reducing it due to lower oil or natural gas prices, operating difficulties, declines in reserves or other reasons. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our business strategies or otherwise take advantage of business opportunities or respond to competitive pressures.

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. 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 report. See above “Item 1. Business — Estimated Proved Reserves” for information about our oil and gas reserves.

In estimating future net revenues from estimated 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 estimated proved reserves referred to in this report is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our estimated proved reserves on an unweighted arithmetic average of the first-day-of-the month price for each month during the 12-month calendar year and year-end costs. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate.

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 estimated 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 SEC 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 natural 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. During the year ended December 31, 2009, the net capitalized cost of our proved oil and gas properties exceeded the ceiling limit and we recorded a non-cash ceiling test impairment of \$754.3 million. See below “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates — Oil and Gas Properties,” and Item 8, Note 1 “Summary of Significant Accounting Policies” in the Notes to the Consolidated Financial Statements for a discussion of our use of the full cost method of accounting for our oil and gas properties and its impact at December 31, 2009. We may incur other 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 estimated 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. 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 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 estimated 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.

Of our total estimated proved reserves, approximately 30% are undeveloped and ultimately may be reclassified as unproved or not be developed, and 20% are developed non-producing and may not be produced.

As of December 31, 2009, approximately 30% of our total estimated proved reserves were undeveloped. The SEC generally requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. Approximately 7.8% of our estimated proved undeveloped reserves as of December 31, 2009 have been classified as such for at least four years. Proved undeveloped reserves that are not timely developed are subject to possible reclassification as non-proved reserves. Substantial downward adjustments to our estimated proved reserves could have a material adverse effect on our financial condition and results of operations, and lower our bank borrowing base and reduce our access to capital. In addition to our proved undeveloped reserves, as of December 31, 2009 approximately 20% of our total estimated proved reserves were developed non-producing. Not all of our undeveloped or developed non-producing reserves ultimately may be developed or produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have 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 do 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 may 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 events and natural disasters, such as loop currents, and 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 natural 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.

Exploration for oil or natural gas in the Gulf of Mexico deepwater 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. Moreover, deepwater projects often lack proximity to the physical and oilfield service infrastructure present in the shallow waters of the Gulf of Mexico, necessitating significant capital investment in subsea flow line infrastructure. Subsea tieback production systems require 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. As a result, a significant amount of time and capital must be invested before we can market 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. See above “Item 1. Business — Properties — Gulf of Mexico Deepwater Operations” for information about our use of tieback technology.

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 typically enter into hedging arrangements pertaining to a substantial portion of our expected future production in order 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. 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.

Counterparty contract default could have an adverse effect on us.

Our revenues are generated under contracts with various counterparties. Results of operations would be adversely affected as a result of non-performance by any of these counterparties of their contractual obligations under the various contracts. A counterparty’s default or non-performance could be caused by factors beyond our control such as a counterparty experiencing credit default. A default could occur as a result of circumstances relating directly to the counterparty, such as defaulting on its credit obligations, or due to circumstances caused by other market participants having a direct or indirect relationship with the counterparty. Defaults by counterparties may occur from time to time, and this could negatively impact our results of operations, financial position and cash flows.

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.

Increased drilling activity periodically results in service cost increases and shortages in drilling rigs, personnel, equipment and supplies in certain areas. 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. Increases in drilling activity in the United States or the Gulf of Mexico could exacerbate this situation.

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, working interest owners 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 United States 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 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 above "Item 1. 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 plugging 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 fully 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 the losses sustained in 2005 from Hurricanes Katrina and Rita and in 2008 from Hurricane Ike, as well as other factors affecting market conditions, premiums and deductibles for certain insurance policies, including windstorm insurance, have increased substantially. 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 certain insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. See above “Item 1. Business — Insurance Matters.”

Although we maintain insurance at levels that 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. 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 Hurricane Ike. See above “Item 1. Business — Insurance Matters” and below “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources” for more information.

The proposed U.S. federal budget for fiscal year 2010 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

The Office of Management and Budget’s proposed U.S. federal budget for fiscal year 2010 repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; levy of an excise tax on Gulf of Mexico oil and gas production; repeal of the manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

Risks Relating to Significant Acquisitions and Other Strategic Transactions

The evaluation and integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. Significant acquisitions and other strategic transactions may involve many risks, including:

- diversion of our management’s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- our exposure to unforeseen liabilities of acquired businesses, operations or properties;
- possibility of faulty assumptions underlying our expectations, including assumptions relating to reserves, future production, volumes, revenues, costs and synergies;
- difficulty associated with coordinating geographically separate organizations; and
- challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating 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 a significant acquisition, our results of operations may be lower than we expect.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, or in oil and natural gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

Financing and other liabilities of a significant acquisition may adversely affect our financial condition and results of operations or be dilutive to stockholders.

Future significant acquisitions and other strategic transactions could result in our incurring additional debt, contingent liabilities and expenses, all of which could decrease our liquidity or otherwise have a material adverse effect on our financial condition and operating results. In addition, an issuance of securities in connection with such transactions could dilute or lessen the rights of our current common stockholders.

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

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

Risks Relating to Financings

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 may require financing beyond our cash flow from operations to fully execute our business plan. 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, and the issuance of debt and equity securities. In the future, we will require substantial capital to fund our business plan and operations. We expect to meet our needs from one or more of our excess cash flow, debt financings and equity offerings. Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development and other activities or be forced to sell some of our assets on unfavorable terms.

The issuance of additional debt would require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions and general corporate requirements, which could place us at a competitive

disadvantage relative to other competitors. Additionally, if revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited. This could also 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.

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. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

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 our debt obligations.

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

- making it more difficult for us to satisfy our debt obligations 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;
- 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 bank 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 bank credit facility and the indentures governing our several series of senior unsecured notes, we must comply with certain financial covenants, including current asset and total debt ratio requirements under the bank credit facility. 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 indentures or the bank credit facility could result in a default under the applicable agreement or a cross default under each 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 that we will be able to generate sufficient cash flow to pay the interest on our debt or those 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 bank 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, the value of our assets and our operating performance at the time of such offering or other financing. We cannot assure that any such offerings, refinancing or sale of assets could be successfully completed.

Ownership of property interests and production operations in areas outside the United States is subject to foreign currency risks.

To the extent we generate revenue outside the U.S., our operations will be sensitive to fluctuations in foreign currency exchange rates, particularly through the weakening of the U.S. dollar relative to other currencies. We may experience currency exchange or other financial losses where we do not take or unsuccessfully take protective measures against exposure to a foreign currency, such as through currency exchange contracts. We also may incur losses as a result of controls over currency exchange or controls over the repatriation of income or capital. Our financial statements, presented in U.S. dollars, are affected by foreign currency fluctuations through both translation risk and transaction risk.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

See “Item 1. Business” for discussion of oil and gas properties and locations.

We have offices in Houston and Midland, Texas; Lafayette, Louisiana; and Calgary, Canada. As of December 31, 2009, our leases covered approximately 102,192 square feet, 6,580 square feet, 14,376 square feet and 3,850 square feet of office space in Houston, Midland, Lafayette and Calgary, respectively. The leases run through October 31, 2018, October 31, 2011, September 30, 2013 and November 30, 2014 in Houston, Midland, Lafayette and Calgary, respectively. The total annual costs of our leases for 2009 were approximately \$3.2 million.

Item 3. Legal Proceedings.

Mariner and its subsidiary, Mariner Energy Resources, Inc. (“MERI”), own numerous properties in the Gulf of Mexico. Certain of such properties were leased from the MMS subject to RRA. Section 304 of the RRA relieves lessees of the obligation to pay royalties on certain leases until after a designated volume has been produced. Four of these leases held by Mariner and two held by MERI that are producing or have produced contain lease language (inserted by the MMS) that conditions royalty relief on commodity prices remaining below specified thresholds. Since 2000, commodity prices have exceeded some of the predetermined thresholds, except in 2002. In May 2006, September 2008 and August 2009, the MMS issued orders asserting that the price thresholds had been exceeded in calendar years 2000, 2001, and each of the years from 2003 through 2008, and, accordingly, that royalties were due under such leases on oil and gas produced in those years (the “Orders”). Mariner and MERI believed that the MMS did not have the statutory authority to include commodity price threshold language in leases governed by Section 304 of the RRA, withheld payment of royalties, and challenged the MMS’s authority in administrative appeals respecting those

leases subject to the Orders. In February 2010, the MMS notified us that it withdrew the Orders, rendering our appeals moot and closing the matter in our favor.

The enforceability of the price threshold provisions in leases granted pursuant to Section 304 of the RRA was being litigated in several administrative appeals filed by other companies in addition to us, as well as in *Kerr-McGee Oil & Gas Corp. v. Allred*, 554 F.3d 1082 (5th Cir.), *cert denied*, *Dep't of the Interior v. Kerr-McGee Oil & Gas Corp.*, 130 S. Ct. 236 (2009). In the *Kerr-McGee* litigation, the district court in the Western District of Louisiana granted Kerr-McGee's motion for summary judgment, ruling that the price threshold provisions are unlawful and unenforceable under Section 304 of the RRA. *Kerr-McGee Oil & Gas Corp. v. Allred*, No. 2:06 CV 0439 (W.D.La.) (Mem. Ruling filed Oct. 30, 2007). The Department of the Interior ("DOI") appealed that judgment to the United States Court of Appeals for the Fifth Circuit. On January 12, 2009, the Fifth Circuit affirmed the district court's judgment that the price provisions are unlawful based on Section 304 of the RRA. On April 14, 2009, the Fifth Circuit denied the DOI's Petition for Rehearing En Banc. On July 13, 2009, the DOI filed a Petition for a Writ of Certiorari with the Supreme Court of the United States. On October 5, 2009, the U.S. Supreme Court denied the Petition for a Writ of Certiorari. Accordingly, the Fifth Circuit's judgment that the price threshold provisions are unlawful and unenforceable under Section 304 of the RRA is final. This judgment was the basis upon which the MMS withdrew the Orders.

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.

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

Not applicable.

Executive Officers of the Registrant

The following table sets forth the names, ages (as of February 22, 2010) and titles of the individuals who are executive officers of Mariner. 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.

<u>Name</u>	<u>Age</u>	<u>Position with Company</u>
Scott D. Josey	52	Chairman of the Board, Chief Executive Officer and President
Dalton F. Polasek	58	Chief Operating Officer
Jesus G. Melendrez	51	Senior Vice President, Chief Commercial Officer, Acting Chief Financial Officer and Treasurer
Mike C. van den Bold	47	Senior Vice President and Chief Exploration Officer
Judd A. Hansen	54	Senior Vice President — Shelf and Onshore
Teresa G. Bushman	60	Senior Vice President, General Counsel and Secretary
Cory L. Loegering	54	Senior Vice President — Deepwater
Murray W. Grigg	54	Vice President — Unconventional Resources
Emily R. McClung	44	Vice President — Human Resources
Michael C. McCullough	64	Vice President — Acquisitions and Divestitures
Richard A. Molohon	55	Vice President — Reservoir Engineering
Kenneth E. Moore, Jr.	63	Vice President — Onshore Land
Charles H. Odom	56	Vice President — Offshore Land and Business Development
R. Cris Sherman	49	Vice President and Chief Accounting Officer

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. He is a director of the Bellville Greater Hospital Foundation and The Association of Former Students of Texas A&M University.

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 and the Society of Petroleum Engineers.

Jesus G. Melendrez — Mr. Melendrez was named Senior Vice President — Chief Commercial Officer and appointed Acting Chief Financial Officer and Treasurer in October 2009. He was promoted to Senior Vice President — Corporate Development in April 2006, serving in that office until October 2009, 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 more than 20 years of industry experience. He is a Certified Petroleum Geologist, a Texas Board Certified Geologist and a member of the American Association of Petroleum Geologists.

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 April 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 30 years of experience in conducting operations in the oil and gas industry.

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.

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 1988, 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 31 years of experience in the industry.

Murray W. Grigg — Mr. Grigg was promoted to Vice President — Unconventional Resources effective March 2010. He joined Mariner in June 2009 as Director, Unconventional Resources with more than 30 years of industry experience as a petroleum engineer. From July 2005 to June 2009, he was Executive Vice President of Kerogen Resources, Inc. which he co-founded to specialize in identifying unconventional oil and gas shale opportunities, particularly in tight gas sands, gas shales and coal bed methane plays in the United States and Canada. He focused on these types of plays as an Engineering Advisor with EnCana Oil & Gas (USA) from 2004 to July 2005, Chief Exploration Engineer with Tom Brown, Inc. from 2003 to 2004, Chief Exploration Engineer with EOG Resources Inc. from 2001 to 2003, and Technical Specialist with EOG Resources Canada, Inc. from 1998 to 2001. Mr. Grigg is a member of the American Association of Petroleum Geologists and Society of Petroleum Engineers.

Emily R. McClung — Ms. McClung was promoted to Vice President — Human Resources effective March 2010, serving as Director of Human Resources from August 2007 to March 2010, and Human Resources Manager from July 2003 to August 2007. She also was employed by Mariner in human resources from November 1997 to June 2002. From June 2002 to July 2003, she was Payroll/Benefits Manager of T3 Energy Services. From August 1988 to November 1997, she was employed by Bank One Texas, N.A. in customer service, human resource and trust support capacities, most recently as Trust Account Specialist in the administration of employee benefit trust plans.

Michael C. McCullough — Mr. McCullough was promoted to Vice President — Acquisitions and Divestitures in February 2008. He served as Manager, Acquisitions/Exploitation from March 2006 to February 2008, and as Senior Reservoir Engineer from May 2004 to March 2006. Mr. McCullough was employed by Basin Exploration, Inc. from 1999 to 2001 and its successor, Stone Energy Corporation, from 2001 to 2004, in general reservoir engineering, lease sales and acquisitions capacities. He has approximately 40 years of industry engineering experience, beginning his career in 1968 as a production engineer with Mobil Oil Corporation.

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 30 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.

Kenneth E. Moore, Jr. — Mr. Moore was promoted to Vice President — Onshore Land in February 2008. A Certified Professional Landman, he was employed by Mariner in December 2004 as Onshore Business Development Manager and in November 2006, became Manager, Land/Business Development (Onshore). Mr. Moore served Mariner from November 2003 to December 2004 as an independent contractor performing land services through his firm Moore Land & Minerals which provided a full range of land services to various clients in the Texas Gulf Coast and the Permian Basin areas from September 2001 to December 2004. Mr. Moore has almost 35 years of industry land experience, beginning his career in 1974 as a landman with Gulf Oil Corporation.

Charles H. Odom — Mr. Odom joined Mariner in April 2009 as Vice President — Offshore Land and Business Development with more than 30 years of industry experience. From October 2007 to February 2009,

he was Chief Executive Officer of White Bay Energy, LLC, which he co-founded to focus on oil and gas exploration and development opportunities in South Texas. From April 2006 to August 2007, Mr. Odom was the Vice President of Santos USA responsible for managing oil and gas assets and projects along the Texas Gulf Coast, on and offshore, and in the U.S. Rocky Mountain region until its assets were sold. From August 2005 to August 2007, he was an independent consultant. In October 2000, Mr. Odom co-founded Gryphon Exploration Company, which focused on the shallow waters in the Gulf of Mexico, serving as its Vice President of Land and Business Development from October 2000 until it was sold in August 2005 to an international oil company. From September 1991 to October 2000, he was President of C. H. Odom Company, a management consulting firm specializing in oil and gas exploration and development transactions in the Gulf of Mexico and onshore Texas.

R. Cris Sherman — Mr. Sherman joined Mariner in October 2009 as Vice President and Chief Accounting Officer with more than 25 years of experience as a Certified Professional Accountant in the energy industry. He was a partner at the professional services firm Sirius Solutions, L.L.L.P. from January 2007 to October 2009, and employed as a director of Sirius from April 2004 until January 2007. From March 2003 to April 2004, he was a Director of Reliant Resources, Inc., primarily responsible for managing accounting for the retail supply group. From February 2002 to March 2003, he was Executive Director — Accounting Policy of UBS Warburg Energy, LLC. From July 1998 to February 2002, Mr. Sherman provided technical accounting and transaction support primarily to the wholesale gas, power trading and finance businesses of Enron North America Corp., most recently as Vice President — Transaction Support in 2001 to 2002, and as a Senior Director and Director before then. He was Director — Internal Audit of Dynegy, Inc. from June 1997 to July 1998. He served in various positions with Eastex Energy Inc. from 1985 to 1988 and 1990 to 1996, most recently as Vice President and Chief Financial Officer from January 1995 to May 1996 and Vice President and Controller from June 1993 to January 1995. From May 1988 to November 1990, he was Vice President and Controller of Houston Gas Exchange Corporation.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Mariner’s common stock trades on the New York Stock Exchange (“NYSE”) under the symbol “ME.” The following table sets forth the reported high and low closing sales prices of our common stock for the periods indicated:

<u>Year</u>	<u>Period Ended</u>	<u>High</u>	<u>Low</u>
2008	First Quarter	\$ 29.60	\$ 23.69
	Second Quarter	37.01	26.84
	Third Quarter	36.45	19.77
	Fourth Quarter	19.54	7.48
2009	First Quarter	\$ 12.59	\$ 6.85
	Second Quarter	15.53	7.87
	Third Quarter	15.19	9.88
	Fourth Quarter	16.09	11.47

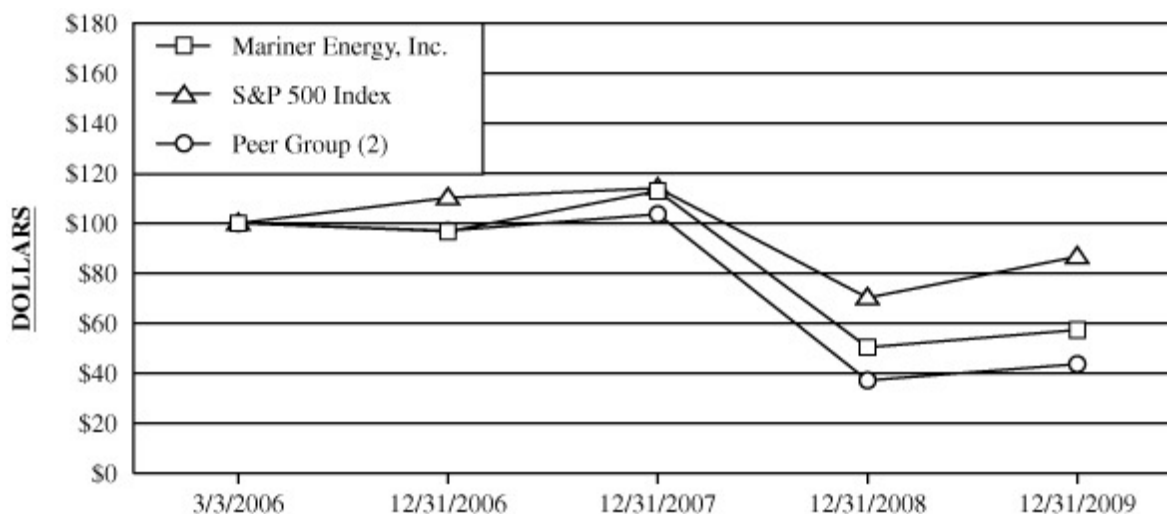
As of February 22, 2010, there were 774 holders of record of our issued and outstanding common stock. We believe that there are significantly more beneficial holders of our stock.

We currently intend to retain our earnings for the development of our business and do not expect to pay any cash dividends. We did not pay any cash dividends for fiscal years 2008 or 2009. Refer below to “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Bank Credit Facility” and Note 3 “Long-Term Debt” in the Notes to the Consolidated Financial Statements in Item 8 for a discussion of certain covenants in our bank credit facility and indentures governing our senior unsecured notes which restrict our ability to pay dividends.

Performance Graph

The following graph compares the cumulative total stockholder return for our common stock to that of the Standard & Poor’s 500 Index and a peer group for the period indicated as prescribed by SEC rules. “Cumulative total return” means the change in share price during the measurement period, plus cumulative dividends for the measurement period (assuming dividend reinvestment), divided by the share price at the beginning of the measurement period. The graph assumes \$100 was invested on March 3, 2006 (the date on which our common stock began regular way trading on the NYSE) in each of our common stock, the Standard & Poor’s Composite 500 Index and a peer group.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG MARINER ENERGY, INC., THE S&P 500 INDEX AND A DEFINED PEER GROUP (1),(2)



Note: The stock price performance of our common stock is not necessarily indicative of future performance.

	Cumulative Total Return(1)				
	Initial	12/31/06	12/31/07	12/31/08	12/31/09
Mariner Energy, Inc.	\$ 100.00	\$ 96.69	\$ 112.88	\$ 50.32	\$ 57.28
S&P 500 Index	\$ 100.00	\$ 110.18	\$ 114.07	\$ 70.17	\$ 86.63
Peer Group(2)	\$ 100.00	\$ 96.98	\$ 103.61	\$ 37.10	\$ 43.61

- (1) Total return assuming reinvestment of dividends. Assumes \$100 invested on March 3, 2006 in each of Mariner’s common stock, the S&P 500 Index, and a peer group of companies. Initial data is taken from March 3, 2006, the date on which Mariner’s common stock began regular way trading on the NYSE.
- (2) Composed of the following seven independent oil and gas exploration and production companies: ATP Oil & Gas Corporation, Callon Petroleum Co., Energy Partners, Ltd., McMoRan Exploration Co., Plains Exploration & Production Company, Stone Energy Corporation, and W&T Offshore, Inc. The 2009 data for Energy Partners, Ltd. reflects adjustment for its issuance on September 21, 2009 of 0.06166332 share of new common stock in exchange for each former one share of common stock outstanding before its emergence from bankruptcy.

The above information under the caption “Performance Graph” shall not be deemed to be “soliciting material” and shall not be deemed to be incorporated by reference by any general statement incorporating by reference this Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, and shall not otherwise be deemed filed under such acts.

Issuer Purchases of Equity Securities

Period	Total Number of Shares (or Units) Purchased	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1, 2009 to October 31, 2009(1)	41,032	\$ 15.74	—	—
November 1, 2009 to November 30, 2009(1)	—	\$ —	—	—
December 1, 2009 to December 31, 2009(1)	495	\$ 13.35	—	—
Total	<u>41,527</u>	\$ 15.68	—	—

(1) These shares were withheld upon the vesting of employee restricted stock grants in connection with payment of required withholding taxes.

Item 6. Selected Financial Data.

The selected financial data table below shows our historical consolidated financial data as of and for each of the five years in the period ended December 31, 2009. The historical consolidated financial data are derived from Mariner’s audited Consolidated Financial Statements, including the consolidated balance sheets at December 31, 2009 and 2008 and the related consolidated statements of operations and cash flows for each of the three years in the period ended December 31, 2009, included herein. You should read the following data in connection with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the Consolidated Financial Statements and related notes thereto included in Part II, Item 8 of this Annual Report on Form 10-K, where there is additional disclosure regarding the information in the following table. Mariner’s historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
(In thousands, except per share data)					
Statement of Operations					
Data(1):					
Total revenues(2)	\$ 942,941	\$ 1,300,507	\$ 874,765	\$ 659,505	\$ 199,710
Operating expenses(3)	282,353	264,832	174,522	105,739	32,218
Depreciation, depletion and amortization	399,400	467,265	384,321	292,180	59,469
General and administrative expense	79,960	60,613	42,151	33,622	36,766
Operating (loss) income(4)	(581,403)	(381,712)	268,710	227,470	69,168
Interest expense, net of amounts capitalized	70,134	56,398	54,665	39,649	8,172
(Benefit) Provision for income taxes	(224,370)	(48,223)	77,324	67,344	21,294
Net (loss) income attributable to Mariner Energy, Inc.	(319,409)	(388,713)	143,934	121,462	40,481
Earnings per common share:					
Net (loss) income per common share — basic	\$ (3.34)	\$ (4.44)	\$ 1.68	\$ 1.59	\$ 1.24
Net (loss) income per common share — diluted	\$ (3.34)	\$ (4.44)	\$ 1.67	\$ 1.58	\$ 1.20

- (1) There are no operating results included for the Edge subsidiaries we acquired on December 31, 2009.
- (2) Includes effects of hedging.
- (3) Operating expenses include lease operating expense, severance and ad valorem taxes and transportation expenses.
- (4) Includes \$754.3 million and \$575.6 million of full cost ceiling test impairments for the years ended December 31, 2009 and 2008.

	December 31,				
	2009	2008	2007	2006	2005
	(In thousands)				
Balance Sheet Data(1):					
Current Assets	\$ 212,321	\$ 374,953	\$ 248,980	\$ 306,018	\$ 141,432
Current Liabilities	372,611	425,564	315,189	239,727	204,006
Working capital deficit	\$ (160,290)	\$ (50,611)	\$ (66,209)	\$ 66,291	\$ (62,574)
Property and equipment, net	2,572,559	2,929,877	2,420,194	2,012,062	515,943
Total assets	2,867,205	3,392,793	3,083,635	2,680,153	665,536
Long-term debt, less current maturities	1,194,850	1,170,000	779,000	654,000	156,000
Stockholders' equity	882,955	1,120,320	1,391,018	1,302,591	213,336

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands)				
Cash Flow Data(1):					
Net cash provided by operating activities	\$ 577,667	\$ 862,017	\$ 536,114	\$ 277,161	\$ 165,444
Net cash used in investing activities	\$ (747,108)	\$ (1,264,784)	\$ (643,780)	\$ (561,390)	\$ (247,799)
Net cash provided by financing activities	\$ 175,109	\$ 387,429	\$ 116,676	\$ 289,252	\$ 84,370

(1) The fair market value of the Edge assets and liabilities we acquired on December 31, 2009 and cash flows from the transaction are included in the tables above.

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

Business Overview

We are an independent oil and natural gas exploration, development and production company with principal operations in the Permian Basin, the Gulf Coast and the Gulf of Mexico. During 2009, we produced approximately 126.5 Bcfe and our average daily production rate was 347 MMcfe. At December 31, 2009, we had 1.087 Tcfe of estimated proved reserves, of which approximately 56% were onshore (47% in the Permian Basin and 8% in the Gulf Coast), with the balance offshore (15% in the Gulf of Mexico deepwater and 29% on the Gulf of Mexico shelf); 53% were natural gas; and 47% were oil and natural gas liquids ("NGLs"). Approximately 66% of our estimated proved reserves were classified as proved developed.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural 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 historically have been very volatile. Oil and natural gas prices increased to, and then declined significantly from, historical highs in mid-2008 and may fluctuate and decline 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.

The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets could lead to an extended worldwide economic recession. A sustained recession or slowdown in economic activity could further reduce worldwide demand for energy and result in lower oil and natural gas prices, which could materially adversely affect our profitability and results of operations.

Securities Offering. On June 10, 2009, we sold and issued in concurrent underwritten offerings \$300.0 million aggregate principal amount of our 11³/₄% senior notes due 2016, and 11.5 million shares of our common stock at a public offering price of \$14.50 per share. We used aggregate proceeds from the concurrent offerings, before deducting estimated offering expenses but after deducting underwriters' discounts and commissions, of approximately \$446.2 million to repay debt under our bank credit facility.

Acquisitions — On December 31, 2009, we acquired the reorganized Edge subsidiaries and operations. The material assets acquired consist primarily of (i) proved reserves estimated by Ryder Scott Company, L.P. as of December 31, 2009 of 100.5 Bcfe, of which approximately 75% are developed (consisting of 69% natural gas and 31% oil and NGLs), 81% are located in South Texas, and 44% are in the Flores/Bloomberg field in Starr County, Texas, (ii) approximately 60,000 net acres of undeveloped leasehold, primarily in Texas and New Mexico, and (iii) deferred tax assets of approximately \$83.3 million, comprised of approximately \$61.2 million in net operating loss carryforwards and \$22.1 million in built-in losses from carryover tax basis in the properties. The effective date of the acquisition was June 30, 2009 and the purchase price was \$260.0 million, less adjustments which resulted in a net purchase price as of December 31, 2009 of approximately \$213.6 million, subject to final adjustments. We financed the net purchase price by borrowing under our secured revolving credit facility.

We recorded a gain on the acquisition of approximately \$107.3 million. A gain on acquisition, or a bargain purchase, can happen in a business combination that is a forced sale in which the seller is acting under compulsion. Edge filed for federal bankruptcy protection in October 2009. In December 2009, we were the winning bidder in the bankruptcy auction for Edge's subsidiaries. In addition to Edge's distressed circumstances, the recent worldwide financial and credit crisis generally depressed financial and commodity markets and demand for energy assets, thereby further increasing the opportunity for a bargain purchase. A buyer is required to recognize in income from continuing operations changes in the amount of its recognizable deferred tax benefits resulting from a business combination when circumstances allow. We structured our purchase of Edge's reorganized subsidiaries as a stock acquisition to obtain the associated tax attributes that we expect to benefit us in future periods. Those attributes were recorded as deferred tax assets on an undiscounted basis in accordance with Accounting Standards Codification Topic 805 "*Business Combinations*" and contributed to the gain recognized on acquisition.

On December 19, 2008, we acquired additional working interests in our existing property, Atwater Valley Block 426 (Bass Lite), for approximately \$30.6 million, increasing our working interest by 11.6% to 53.8%.

On February 29, 2008 and December 1, 2008 we acquired additional working interests in certain of our existing properties in the Spraberry field in the Permian Basin. We operate substantially all of the assets. The purchase prices were \$23.5 million for the February 2008 acquisition and \$19.4 million for the December 2008 acquisition.

On January 31, 2008, we acquired 100% of the equity in a subsidiary of Hydro Gulf of Mexico, Inc. pursuant to a Membership Interest Purchase Agreement executed on December 23, 2007. The acquired subsidiary, now known as Mariner Gulf of Mexico LLC ("MGOM"), was an indirect subsidiary of StatoilHydro ASA and owns substantially all of its former Gulf of Mexico shelf operations. We paid \$228.8 million for MGOM.

Results of Operations

Year Ended December 31, 2009 compared to Year Ended December 31, 2008

**Operating and Financial Results for the Year Ended December 31, 2009
Compared to the Year Ended December 31, 2008**

	<u>Year Ended December 31,</u>		<u>Increase (Decrease)</u>	<u>% change</u>
	<u>2009</u>	<u>2008</u>		
(In thousands, except average sales price and unit costs)				
Summary Operating Information:				
Net Production:				
Natural gas (MMcf)	90,801	79,756	11,045	14%
Oil (MBbls)	4,472	4,881	(409)	(8)%
Natural gas liquids (MBbls)	1,478	1,558	(80)	(5)%
Total natural gas equivalent (MMcfe)	126,498	118,389	8,109	7%
Average daily production (MMcfe per day)	347	323	24	7%
Hedging Activities:				
Natural gas revenue gain (loss)	\$ 187,857	\$ (28,047)	\$ 215,904	770%
Oil revenue gain (loss)	44,801	(72,762)	117,563	162%
Total hedging revenue gain (loss)	\$ 232,658	\$ (100,809)	\$ 333,467	331%
Average Sales Prices:				
Natural gas (per Mcf) realized(1)	\$ 6.08	\$ 9.31	\$ (3.23)	(35)%
Natural gas (per Mcf) unhedged	4.01	9.66	(5.65)	(58)%
Oil (per Bbl) realized(1)	70.59	86.02	(15.43)	(18)%
Oil (per Bbl) unhedged	60.57	100.93	(40.36)	(40)%
Natural gas liquids (per Bbl) realized(1)	33.10	55.02	(21.92)	(40)%
Natural gas liquids (per Bbl) unhedged	33.10	55.02	(21.92)	(40)%
Total natural gas equivalent (\$/Mcf) realized(1)	7.25	10.54	(3.29)	(31)%
Total natural gas equivalent (\$/Mcf) unhedged	5.41	11.39	(5.98)	(53)%
Summary of Financial Information:				
Natural gas revenue	\$ 552,259	\$ 742,370	\$ (190,111)	(26)%
Oil revenue	315,642	419,878	(104,236)	(25)%
Natural gas liquids revenue	48,921	85,715	(36,794)	(43)%
Other revenues	26,119	52,544	(26,425)	(50)%
Lease operating expense	249,449	231,645	17,804	8%
Severance and ad valorem taxes	14,410	18,191	(3,781)	(21)%
Transportation expense	18,494	14,996	3,498	23%
General and administrative expense	79,960	60,613	19,347	32%
Depreciation, depletion and amortization	399,400	467,265	(67,865)	(15)%
Full cost ceiling test impairment	754,325	575,607	178,718	31%
Goodwill impairment	—	295,598	(295,598)	(100)%
Other property impairment	—	15,252	(15,252)	(100)%
Other miscellaneous expense	8,306	3,052	5,254	172%
Net interest expense	69,635	55,036	14,599	27%
Gain on acquisition	107,259	—	107,259	N/A
Loss before taxes	(543,779)	(436,748)	107,031	25%
Benefit for income taxes	(224,370)	(48,223)	176,147	365%
Net Loss	(319,409)	(388,525)	(69,116)	(18)%
Less: Net income attributable to noncontrolling interest	—	(188)	(188)	(100)%
Net Loss attributable to Mariner Energy, Inc.	\$ (319,409)	\$ (388,713)	\$ (69,304)	(18)%
Average Unit Costs per Mcfe:				
Lease operating expense	\$ 1.97	\$ 1.96	\$ 0.01	1%
Severance and ad valorem taxes	0.11	0.15	(0.04)	(27)%
Transportation expense	0.15	0.13	0.02	15%
General and administrative expense	0.63	0.51	0.12	24%
	3.16	3.95	(.79)	(20)%

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

Net Loss attributable to Mariner Energy, Inc. for 2009 was \$319.4 million compared to \$388.7 million for 2008. The decrease was primarily attributable to an \$132.1 million decrease in impairments, a \$67.9 million decrease in depreciation, depletion and amortization and a \$176.1 million increase in income tax benefit. These were partially offset by a decrease in revenues of \$357.6 million, a \$107.3 million gain on acquisition and an increase in general and administrative expense of \$19.3 million. Basic and diluted earnings per share for 2009 were \$(3.34) for each measure compared to \$(4.44) for each measure for 2008.

Net Production for 2009 was approximately 126.5 Bcfe, up 8.1 Bcfe or 6.8% from 118.4 Bcfe from 2008. Natural gas production for 2009 comprised approximately 72% of total production compared to approximately 67% for 2008.

Natural gas production for 2009 increased 14% to approximately 249 MMcf per day, compared to approximately 218 MMcf per day for 2008. Oil production for 2009 decreased 8% to approximately 12,251 barrels per day, compared to approximately 13,300 barrels per day for 2008. Natural gas liquids production for 2009 decreased 5% to approximately 4,049 barrels per day, as compared to approximately 4,257 barrels per day for 2008.

Period over period changes in our production were primarily attributable to the following:

- Increased production of 3.4 Bcfe, or 23%, from our onshore properties, primarily as a result of our drilling and development of existing acreage in the Permian Basin.
- Increased production of 12.4 Bcfe, or 31%, from our Gulf of Mexico deepwater properties, due primarily to Bass Lite located in Atwater Valley 426 (which contributed 9.9 Bcfe) and Geauxpher located in Garden Banks 462 (which contributed 13.0 Bcfe), partially offset by decreases at Pluto located in Mississippi Canyon 674 (which contributed 3.1 Bcfe) and Northwest Nansen located in East Breaks 602 (which contributed 6.0 Bcfe).
- Decreased production of 7.7 Bcfe, or 12%, from our Gulf of Mexico shelf properties as a result of normal depletion declines and production interruptions due to repairs on certain fields totaling 18.8 Bcfe, partially offset by increased production of 11.1 Bcfe at certain of our properties including High Island 116 (which contributed 3.4 Bcfe) and South Marsh Island 76 (which contributed 1.1 Bcfe).

Natural gas, oil and NGL revenues for 2009 decreased 27% to \$916.8 million compared to \$1,248.0 million for 2008 as a result of lower realized prices (approximately \$416.6 million, net of the effect of hedging), which was partially offset by increased production (approximately \$85.5 million).

During 2009, our revenues reflected a net recognized hedging gain of \$232.7 million, comprised of \$173.7 million in favorable cash settlements on our hedges, a \$58.7 million reclassification on our liquidated swaps in 2009 and an unrealized gain of approximately \$0.3 million related to the ineffective portion of open contracts that are not eligible for deferral in conformity with accounting for derivatives and hedging under GAAP due primarily to the basis differentials between the contract price and the indexed price at the point of sale. This compares to a net recognized hedging loss of approximately \$100.8 million for 2008, comprised of \$98.8 million in unfavorable cash settlements and an unrealized loss of \$2.0 million related to the ineffective portion not eligible for deferral under GAAP.

Our natural gas and oil average sales prices, and the effects of hedging activities on those prices, are listed in the table below. We did not conduct hedging activities related to NGL sales for the years ended December 31, 2009 and 2008.

	<u>Realized</u>	<u>Unhedged</u>	<u>Hedging (Loss) Gain</u>	<u>% Change</u>
Year Ended December 31, 2009:				
Natural gas (per Mcf)	\$ 6.08	\$ 4.01	\$ 2.07	52%
Oil (per Bbl)	70.59	60.57	10.02	17%
Year Ended December 31, 2008:				
Natural gas (per Mcf)	\$ 9.31	\$ 9.66	\$ (0.35)	(4)%
Oil (per Bbl)	86.02	100.93	(14.91)	(15)%

Other revenues for 2009 decreased approximately \$26.4 million to \$26.1 million from \$52.5 million for 2008 due primarily to the release of suspended revenue of \$46.5 million in 2008 related to a potential MMS royalty liability and imputed rent income of \$4.3 million in 2008 from the lease of office property acquired in January 2008, partially offset by a \$16.6 million arbitration award related to a consummated acquisition and \$7.4 million in third party gas sales on commodities purchased to satisfy our pipeline transportation commitments (discussed in other miscellaneous expense).

Lease operating expense (“LOE”) for 2009 increased approximately \$17.8 million to \$249.4 million from \$231.6 million for 2008, primarily due to increased costs of \$16.5 million attributable to processing fees primarily related to Atwater 426 (Bass Lite) and Garden Banks 462 (Geauxpfer) not included in first three quarters of 2008 due to production on those fields commencing subsequent to that period, \$19.9 million of repairs on certain properties (including \$2.6 million on South Marsh Island 11 and \$1.9 million on Eugene Island 292) and \$11.8 million for repairs related to Hurricane Ike. These increases were offset by a decrease of \$24.0 million in the retrospective contingent OIL insurance premium.

Severance and ad valorem tax for 2009 decreased approximately \$3.8 million to \$14.4 million from \$18.2 million for 2008 due to lower production taxes of \$4.5 million, partially offset by increased ad valorem taxes of \$0.7 million.

Transportation expense for 2009 increased approximately \$3.5 million to \$18.5 million from \$15.0 million for 2008 due primarily to increased expense at Bass Lite located in Atwater 426.

General and administrative expense (“G&A”) for 2009 increased approximately \$19.4 million to \$80.0 million from \$60.6 million for 2008. The increase was due primarily to an increase in share-based compensation expense of approximately \$8.1 million to \$29.1 million from \$21.0 million for 2008. Of this increase, \$4.6 million was attributable to long-term performance-based restricted stock awarded during 2008 and \$3.5 million was due to shares of restricted stock grants made during 2009. See Note 5 “Share-Based Compensation” in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K for more detail on stock grants. Professional fees and salaries and wages increased \$11.4 million to \$63.2 million from \$51.8 million in 2008, mainly due to non-recurring projects and additional headcount. Capitalized G&A related to our acquisition, exploration and development activities increased \$1.4 million to \$21.2 million from \$19.8 million in 2008.

Depreciation, depletion, and amortization expense (“DD&A”) for 2009 decreased approximately \$67.9 million to \$399.4 million (\$3.16 per Mcfe) from \$467.3 million (\$3.95 Mcfe) for 2008. This decrease primarily resulted from the effects of ceiling test impairments in 2009 and 2008 of \$704.7 million and \$575.6 million, respectively, that substantially lowered the basis of our oil and gas properties. The change in the depletion rate resulted in a \$107.4 million decrease in expense, partially offset by a \$30.2 million increase in expense due to higher production for 2009 as compared to 2008.

Full cost ceiling test impairment of \$49.6 million was recognized for the fourth quarter 2009 and \$704.7 million was recognized for the first quarter 2009 as a result of the net capitalized cost of our proved

oil and gas properties exceeding our ceiling limit. See “— Critical Accounting Policies and Estimates — Full Cost Ceiling Test” for more detail on this impairment.

Goodwill impairment of \$295.6 million was recorded in the fourth quarter 2008 as a result of our annual impairment test. The goodwill was originally recorded in conjunction with a merger transaction consummated in March 2006 and the impairment was a result of weakened economic conditions and a decline in our stock price during the fourth quarter 2008. See “— Critical Accounting Policies and Estimates — Goodwill” for more detail on this impairment. The impairment reduced our net goodwill balance to \$0 at December 31, 2008 and therefore no goodwill impairment was noted during 2009.

Other property impairment of \$15.3 million was recognized as a result of our annual impairment assessment performed on our other property at December 31, 2008. See “— Critical Accounting Policies and Estimates — Other Property” for more detail on this impairment. No property impairment was recognized during 2009.

Other miscellaneous expense for 2009 increased approximately \$5.3 million to \$8.3 million from \$3.0 million for 2008, due primarily to third party gas purchases of \$6.8 million made to satisfy our pipeline transportation commitments, the sales of which are included in other miscellaneous income and increased ad valorem tax of \$1.3 million, partially offset by a decrease in bad debt expense of approximately \$2.9 million.

Net interest expense for 2009 increased approximately \$14.6 million to \$69.6 million from \$55.0 million for 2008, due primarily to increased interest expense of \$20.9 million as a result of our issuance of 11³/₄% senior notes due 2016, partially offset by decreased interest expense of \$8.4 million on our credit facility as a result of lower interest rates and reduced borrowing in 2009 as compared to 2008 and increased capitalized interest of \$5.1 million.

Gain on acquisition for 2009 of \$107.3 was recognized as a result of our acquisition of the reorganized Edge subsidiaries and operations. See Note 2 “Acquisitions” in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K for more detail.

Provision for income taxes for 2009 reflected an effective tax rate of 41.3% as compared to 11.0% for 2008. The increase in our effective tax rate was due primarily to the effect of a permanent non-deductible goodwill impairment of \$295.6 million in 2008 and a permanent book-tax difference attributable to the non-taxable gain on acquisition of \$107.3 million in 2009 discussed above. The 2009 effective tax rate excluding the non-taxable gain on acquisition would have been 34.5%. The 2008 effective tax rate excluding the goodwill impairment would have been 34.2%.

Year Ended December 31, 2008 compared to Year Ended December 31, 2007

**Operating and Financial Results for the Year Ended December 31, 2008
Compared to the Year Ended December 31, 2007**

	<u>Year Ended December 31,</u>		<u>Increase</u>	<u>% change</u>
	<u>2008</u>	<u>2007</u>	<u>(Decrease)</u>	
	(In thousands, except average sales price and unit costs)			
Summary Operating Information:				
Net Production:				
Natural gas (MMcf)	79,756	67,793	11,963	18%
Oil (MBbls)	4,881	4,214	667	16%
Natural gas liquids (MBbls)	1,558	1,200	358	30%
Total natural gas equivalent (MMcfe)	118,389	100,273	18,116	18%
Average daily production (MMcfe per day)	323	275	48	18%
Hedging Activities:				
Natural gas revenue gain (loss)	\$ (28,047)	\$ 58,465	\$ (86,512)	(148)%
Oil revenue loss	(72,762)	(13,388)	(59,374)	443%
Total hedging revenue gain (loss)	\$ (100,809)	\$ 45,077	\$ (145,886)	(324)%
Average Sales Prices:				
Natural gas (per Mcf) realized(1)	\$ 9.31	\$ 7.88	\$ 1.43	18%
Natural gas (per Mcf) unhedged	9.66	7.02	2.64	38%
Oil (per Bbl) realized(1)	86.02	67.50	18.52	27%
Oil (per Bbl) unhedged	100.93	70.68	30.25	43%
Natural gas liquids (per Bbl) realized(1)	55.02	45.16	9.86	22%
Natural gas liquids (per Bbl) unhedged	55.02	45.16	9.86	22%
Total natural gas equivalent (\$/Mcf) realized(1)	10.54	8.71	1.83	21%
Total natural gas equivalent (\$/Mcf) unhedged	11.39	8.26	3.13	38%
Summary of Financial Information:				
Natural gas revenue	\$ 742,370	\$ 534,537	\$ 207,833	39%
Oil revenue	419,878	284,405	135,473	48%
Natural gas liquids revenue	85,715	54,192	31,523	58%
Other revenues	52,544	1,631	50,913	3,122%
Lease operating expense	231,645	152,627	79,018	52%
Severance and ad valorem taxes	18,191	13,101	5,090	39%
Transportation expense	14,996	8,794	6,202	71%
General and administrative expense	60,613	42,151	18,462	44%
Depreciation, depletion and amortization	467,265	384,321	82,944	22%
Full cost ceiling test impairment	575,607	—	575,607	N/A
Goodwill impairment	295,598	—	295,598	N/A
Other property impairment	15,252	—	15,252	N/A
Other miscellaneous expense	3,052	5,061	(2,009)	(40)%
Other income	—	5,811	(5,811)	(100)%
Net interest expense	55,036	53,262	1,774	3%
Income (Loss) before taxes	(436,748)	221,259	(658,007)	(297)%
(Benefit) Provision for income taxes	(48,223)	77,324	(125,547)	(162)%
Net Income (Loss)	(388,525)	143,935	(532,460)	(370)%
Less: Net income attributable to noncontrolling interest	(188)	(1)	(187)	(18,700)%
Net Income (Loss) attributable to Mariner Energy, Inc.	\$ (388,713)	\$ 143,934	\$ (532,647)	(370)%
Average Unit Costs per Mcfe:				
Lease operating expense	\$ 1.96	\$ 1.52	\$ 0.44	29%
Severance and ad valorem taxes	0.15	0.13	0.02	15%
Transportation expense	0.13	0.09	0.04	44%
General and administrative expense	0.51	0.42	0.09	21%
Depreciation, depletion and	3.95	3.83	0.12	3%

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

Net Loss attributable to Mariner Energy, Inc. for 2008 was \$388.7 million compared to net income of \$143.9 million for 2007. The decrease was primarily attributable to \$886.5 million in impairments resulting

from our full cost ceiling test, other property impairment and goodwill, as discussed below. Basic and fully-diluted earnings per share for 2008 were \$(4.44) for each measure compared to \$1.68 and \$1.67, respectively for 2007.

Net production Natural gas production increased approximately 18% in 2008 to approximately 218 MMcf per day, compared to approximately 186 MMcf per day in 2007. Oil production increased 16% in 2008 to approximately 13,300 barrels per day, compared to approximately 11,500 barrels per day in 2007. Natural gas liquids production increased 30% in 2008 and total overall production increased 18% in 2008 to approximately 323 MMcfe per day, compared to 275 MMcfe per day in 2007. Natural gas production comprised approximately 67% of total production in both 2008 and 2007.

Net production in the Gulf of Mexico for 2008 increased 16% to 103.5 Bcfe from 89.1 Bcfe for 2007 primarily reflecting the start up in 2008 of production from several new projects, most notably, Northwest Nansen located in East Breaks 602 (which contributed 12.9 Bcfe) and Bass Lite located in Atwater 426 (which contributed 8.4 Bcfe), and the impact of our acquisition of MGOM (which contributed 13.1 Bcfe). This increase was offset by the impacts of Hurricanes Gustav and Ike in the third quarter which resulted in net shut-in production (assuming pre-hurricane net production levels remained constant) of approximately 20 Bcfe.

Onshore production for 2008 increased 33% to 14.9 Bcfe from 11.2 Bcfe for 2007, primarily as a result of our acquisition of additional interests and drilling and development of existing acreage in the Permian Basin (which contributed 2.6 Bcfe in 2008).

Natural gas, oil and NGL revenues for 2008 increased 43% to \$1,248.0 million compared to \$873.1 million for 2007 as a result of increased pricing (approximately \$217.1 million, net of the effect of hedging), and increased production (approximately \$157.8 million).

During 2008, our revenues reflected a net recognized hedging loss of \$100.8 million comprised of \$98.8 million in unfavorable cash settlements on our hedges and an unrealized loss of \$2.0 million related to the ineffective portion of open contracts that are not eligible for deferral in conformity with accounting for derivatives and hedging under GAAP due primarily to the basis differentials between the contract price and the indexed price at the point of sale. This compares to a net recognized hedging gain of approximately \$45.1 million for 2007, comprised of \$46.7 million in favorable cash settlements and an unrealized loss of \$1.6 million related to the ineffective portion not eligible for deferral under GAAP.

Our natural gas and oil average sales prices, and the effects of hedging activities on those prices, were as follows:

	<u>Realized</u>	<u>Unhedged</u>	<u>Hedging (Loss) Gain</u>	<u>% Change</u>
Year Ended December 31, 2008:				
Natural gas (per Mcf)	\$ 9.31	\$ 9.66	\$ (0.35)	(4)%
Oil (per Bbl)	86.02	100.93	(14.91)	(15)%
Year Ended December 31, 2007:				
Natural gas (per Mcf)	\$ 7.88	\$ 7.02	\$ 0.86	12%
Oil (per Bbl)	67.50	70.68	(3.18)	(4)%

Other revenues for 2008 increased approximately \$50.9 million to \$52.5 million from \$1.6 million for 2007 as a result of the release of suspended revenue of \$46.5 million related to a potential MMS royalty liability and \$4.3 million of imputed rent from the lease of office property acquired in January 2008.

Lease operating expense for 2008 increased approximately \$79.0 million to \$231.6 million from \$152.6 million for 2007, primarily as a result of a \$36.0 million multiple-year retrospective contingent OIL insurance premium.

LOE also was imparted by start-up of production in February 2008 from Bass Lite and Northwest Nansen, the acquisition of MGOM in January 2008, and the impact of the additional Permian Basin assets acquired at year-end 2007, which are long-lived and typically carry a higher per-unit LOE.

Severance and ad valorem tax for 2008 increased approximately \$5.1 million to \$18.2 million from \$13.1 million for 2007 due to increased severance as a result of higher oil prices and increased production from the drilling and completion of additional wells and our acquisition of additional interests in the Permian Basin.

Transportation expense for 2008 increased approximately \$6.2 million to \$15.0 million from \$8.8 million for 2007 due primarily to commencement of production in 2008 at Bass Lite, Northwest Nansen, Galveston 352 and High Island A467.

General and administrative expense for 2008 increased approximately \$18.4 million to \$60.6 million from \$42.2 million for 2007. The increase was due primarily to an increase in share-based compensation expense of approximately \$10.1 million to \$21.0 million from \$10.9 million for 2007. This increase was due primarily to long-term performance-based restricted stock awarded during 2008. See Note 5 “Share-Based Compensation” in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K for more detail on stock grants. Beginning in 2008, that portion of Lafayette and Midland office expense that is directly related to production activity was classified as LOE, and we began capitalizing share-based compensation expense attributable to those non-officer employees directly engaged in exploration, development and acquisition activities. Capitalized G&A related to our acquisition, exploration and development activities increased \$5.8 million to \$19.8 million in 2008 from \$14.0 million in 2007.

Depreciation, depletion, and amortization expense for 2008 increased approximately \$83.0 million to \$467.3 million from \$384.3 million for 2007, primarily as a result of increased production from our acquisitions of MGOM and additional interests in the Permian Basin properties, and start-up production from Bass Lite and Northwest Nansen.

Full cost ceiling test impairment of \$575.6 million was recognized in December 2008 as a result of the net capitalized cost of our proved oil and gas properties exceeding our ceiling limit. See “— Critical Accounting Policies and Estimates — Oil and Gas Properties” for more detail on this impairment.

Goodwill impairment of \$295.6 million was recorded in the fourth quarter 2008 as a result of our annual impairment test. The goodwill was originally recorded in conjunction with a merger transaction consummated in March 2006 and the impairment is a result of weakened economic conditions and a decline in our stock price during the fourth quarter 2008. See “— Critical Accounting Policies and Estimates — Goodwill” for more detail on this impairment.

Other property impairment of \$15.3 million was recognized as a result of our annual impairment assessment performed on our other property. See “— Critical Accounting Policies and Estimates — Other Property” for more detail on this impairment.

Net interest expense for 2008 increased approximately \$1.7 million to \$55.0 million from \$53.3 million for 2007 due primarily to an increase in average daily debt levels, partially offset by lower interest rates, and an additional four months of interest expense related to our 8% Senior Notes due 2017 issued on April 30, 2007. Capitalized interest increased to \$9.7 million in 2008 from \$0.5 million in 2007.

Provision for income taxes for 2008 reflected an effective tax rate of 11.0% as compared to 34.9% for 2007. The decrease in our effective tax rate was due primarily to a permanent book-tax difference attributable to the goodwill impairment discussed above. Excluding this permanent book-tax difference, the effective rate for 2008 would have been 34.2%.

Liquidity and Capital Resources

Financial Condition

	Years Ended December 31,	
	2009	2008
	(In thousands, except ratios)	
Current ratio(1)	0.6 to 1	0.9 to 1
Working capital deficit(2)	\$ (160,290)	\$ (50,611)
Total debt	\$ 1,194,850	\$ 1,170,000
Operating cash flow(3)	\$ 531,149	\$ 885,887
Interest expense, net of capitalization	\$ 70,134	\$ 56,398
Fixed-charge coverage ratio(4)	—	—
Total cash and marketable securities less debt(5)	\$ (1,185,931)	\$ (1,166,749)
Stockholders' equity	\$ 882,955	\$ 1,120,320
Total liabilities to equity	2.25 to 1	2.03 to 1

- (1) Current ratio is current assets divided by current liabilities.
- (2) Working capital deficit is the difference between current assets and current liabilities.
- (3) Operating cash flow is net cash provided by operating activities, plus or minus changes in operating assets and liabilities. See the following “Reconciliation of Non-GAAP Measure: Operating Cash Flow.”
- (4) Fixed-charge coverage ratio is net earnings before taxes, net income attributable to noncontrolling interest and fixed charges divided by fixed charges (interest expense, net of capitalization plus amortization of discounts). Due to loss from operations in 2009 and 2008, the ratio coverage was less than 1:1. We would have needed to generate additional earnings of \$558,440 and \$446,399 respectively, to achieve a coverage of 1:1 for that period.
- (5) Total cash and marketable securities less debt is cash and cash equivalents less long-term debt.

Reconciliation of Non-GAAP Measure: Operating Cash Flow

Operating cash flow (“OCF”) is not a financial or operating measure under GAAP. The table below reconciles OCF to related GAAP information. We believe that OCF 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 OCF should not be considered in isolation or as a substitute for net income, operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with GAAP or as a measure of our profitability or liquidity.

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Net cash provided by operating activities (GAAP)	\$ 577,667	\$ 862,017
Changes in operating assets and liabilities	(46,518)	23,870
Operating cash flow (Non-GAAP)	\$ 531,149	\$ 885,887

2009 Cash Flows

The following table presents cash payments for interest and income taxes:

	Years Ended December 31,		
	2009	2008	2007
	(In millions)		
Cash payments for interest, net of capitalized interest	\$ 68.9	\$ 62.2	\$ 49.1
Net cash (refunds) payments for income taxes	(2.0)	2.9	\$ 0.6

Net cash provided by operating activities decreased by \$284.3 million to \$577.7 million in 2009 from \$862.0 million in 2008. The decrease was due primarily to lower revenue resulting from a decrease in realized prices of \$416.6 million, partially offset by increased production of \$85.5 million and a \$16.6 million arbitration award.

As of December 31, 2009, we had a working capital deficit of \$160.3 million, due in part to a non-cash current derivative liability and non-cash abandonment liability offset by a non-cash deferred income tax assets and \$11.1 million related to the fair market value of current assets acquired in connection with the acquisition of the reorganized Edge subsidiaries and operations. In addition, working capital was negatively impacted by accrued capital expenditures. This deficit will be funded by cash flow from operating activities and our bank credit facility, as needed.

Net cash flows used in investing activities decreased by \$517.7 million to \$747.1 million in 2009 from \$1,264.8 million in 2008 due primarily to decreased capital expenditures attributable to reduced activity in our drilling programs partially offset by the 2009 acquisition of the Edge subsidiaries and operations for approximately \$213.6 million. Additionally, 2008 was impacted by the acquisition of MGOM, including approximately \$15.0 million of mid-stream assets reflected in other property, and an increase in other property reflecting an investment of approximately \$34.6 million in office property.

Net cash flows provided by financing activities decreased by \$212.3 million to \$175.1 million for 2009 from \$387.4 million for 2008. The decrease was due primarily to \$656.0 million net increased repayments under our bank credit facility, net of borrowings of approximately \$213.6 million in December 2009 to finance the purchase of the Edge subsidiaries and operations and \$223.5 million in January 2008 to finance the purchase of MGOM. The decrease was partially offset by \$446.2 million of proceeds (before deducting estimated offering expenses but after deducting underwriters' discounts and commissions) from debt and securities offerings in June 2009.

2009 Uses of Capital. Our primary uses of capital during 2009 were as follows:

- funding capital expenditures (excluding hurricane repairs and acquisitions) of approximately \$524.3 million;
- funding hurricane repairs and hurricane-related abandonment expenditures (net of insurance recoveries) of approximately \$6.6 million;
- paying interest of approximately \$68.9 million;
- funding the purchase of the Edge subsidiaries and operations for approximately \$213.6 million; and
- paying routine operating and administrative expenses.

2009 Capital Expenditures. The following table presents major components of our capital expenditures during 2009 compared to 2008.

	Year Ended December 31,	
	2009	2008
(In thousands)		
Capital expenditures:		
Oil and natural gas development	\$ 306,834	\$ 588,456
Oil and natural gas property acquisitions	236,661	302,629
Oil and natural gas exploration	182,863	270,767
Leasehold acquisitions	21,942	152,567
Corporate expenditures and other	38,462	66,668
Total capital expenditures, net of proceeds from property conveyances	\$ 786,762	\$ 1,381,087

2009 Hurricane Expenditures. During the year ended 2009, we incurred approximately \$81.7 million in hurricane expenditures resulting from Hurricanes Ike and Gustav, of which \$22.7 million were repairs and \$59.0 were capital expenditures. Since 2004, we have incurred approximately \$321.5 million in hurricane

expenditures from Hurricanes Ike, Gustav, Ivan, Katrina and Rita, of which \$23.5 million were repairs, \$193.9 were capital expenditures and \$104.1 million were hurricane-related abandonment costs. Net of our deductible of \$24.8 million and insurance proceeds received of \$185.1 million, our insurance receivable at December 31, 2008 was \$8.5 million, all of which is expected to be settled within the next 12 months. However, due to the magnitude of Hurricanes Ike, Katrina and Rita and the complexity of the insurance claims being processed by the insurance industry, the timing of our ultimate insurance recovery cannot be assured. We expect to maintain a potentially significant insurance receivable through 2010 in respect of Hurricane Ike while we actively pursue settlement of our claims to minimize the impact to our working capital and liquidity. We expect to recover substantially all of our outstanding OIL claims in respect of Hurricanes Katrina and Rita by 2010. Any differences between our insurance recoveries and insurance receivables will be recorded as adjustments to our oil and natural gas properties.

2009 Sources of Capital. Our primary sources of capital during 2009 were as follows:

- cash flow from operations;
- net proceeds from sale of senior notes and common stock;
- borrowings under our revolving bank credit facility; and
- insurance proceeds.

Bank Credit Facility — We have a secured revolving credit facility with a group of banks pursuant to an amended and restated credit agreement dated March 2, 2006, as further amended. The credit facility matures January 31, 2012 and is subject to a borrowing base which is redetermined periodically. As of December 31, 2009, maximum credit availability under the facility was \$1.0 billion, including up to \$50.0 million in letters of credit, subject to a borrowing base of \$800.0 million scheduled to be redetermined in February 2010. The redetermination was pending on February 28, 2010, and we anticipate that it will occur in March 2010.

The lenders redetermine the borrowing base periodically based upon their evaluation of our oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders. The outstanding principal balance of loans under the credit facility may not exceed the borrowing base. If the borrowing base falls below the sum of the amount borrowed and uncollateralized letter of credit exposure, then to the extent of the deficit, we must prepay borrowings and cash collateralize letter of credit exposure, pledge additional unencumbered collateral, repay borrowings and cash collateralize letters of credit on an installment basis, or effect some combination of these actions.

We have used borrowings under the facility to facilitate acquisitions, and have used and may use borrowings under the facility for general corporate purposes. On June 10, 2009, we used aggregate proceeds from concurrent offerings of our 11^{3/4}% senior notes due 2016 and common stock, before deducting estimated offering expenses but after deducting underwriters' discounts and commissions, of approximately \$446.2 million to repay debt under our bank credit facility. These offerings are discussed further below. We funded our December 2009 acquisition of the Edge subsidiaries and operations by borrowing approximately \$213.6 million under the credit facility.

As of December 31, 2009 and 2008, advances outstanding under the credit facility were \$305.0 million and \$570.0 million, respectively. In addition, as of December 31, 2009 four letters of credit were outstanding totaling \$4.7 million, of which \$4.2 million is required for plugging and abandonment obligations at certain of our offshore fields. As of December 31, 2009, after accounting for the \$4.7 million of letters of credit, we had \$490.3 million available to borrow under the credit facility.

Borrowings under the bank credit facility bear interest at either a LIBOR-based rate or a prime-based rate, at our option, plus a specified margin. At December 31, 2009, when borrowings at both LIBOR and prime-based rates were outstanding, the blended interest rate was 3.40% on all amounts borrowed. At December 31, 2008, the interest rate was 3.31%. During the year ended December 31, 2009, the commitment fee on unused capacity was 0.250% to 0.375% per annum through March 23, 2009 and 0.5% per annum thereafter.

The credit facility subjects us to various restrictive covenants and contains other usual and customary terms and conditions, including limits on additional debt, cash dividends and other restricted payments, liens, investments, asset dispositions, mergers and speculative hedging. Financial covenants under the credit facility require us to:

- maintain a ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities of not less than 1.0 to 1.0; and
- maintain a ratio of total debt to EBITDA (as defined in the credit agreement) of not more than 2.5 to 1.0.

We were in compliance with these and other credit facility covenants as of December 31, 2009 when the ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities was 2.38 to 1.0 and the ratio of total debt to EBITDA was 1.99 to 1.0. Our breach of these covenants would be an event of default, after which the lenders could terminate their lending obligations and accelerate maturity of any outstanding indebtedness under the credit facility which then would become due and payable in full. An unrescinded acceleration of maturity under the bank credit facility would constitute an event of default under our senior notes described below, which could trigger acceleration of maturity of the indebtedness evidenced by the senior notes.

Our payment and performance of obligations under the credit facility (including any obligations under commodity and interest rate hedges entered into with facility lenders) are secured by liens upon substantially all of our assets and the assets of our subsidiaries, except our Canadian subsidiary, and guaranteed by our subsidiaries, other than Mariner Energy Resources, Inc. which is a co-borrower, and our Canadian subsidiary.

Senior Notes — Mariner has outstanding the following three issues of debt issued in registered transactions, referred to collectively as the “Notes”:

- \$300 million principal amount of 11^{3/4}% Senior Notes due 2016 issued in June 2009 (“the 11^{3/4}% Notes”);
- \$300 million principal amount of 8% Senior Notes due 2017 issued in April 2007 (“the 8% Notes”); and
- \$300 million principal amount of 7^{1/2}% Senior Notes due 2013 issued in April 2006 (“the 7^{1/2}% Notes”).

We sold and issued the 11^{3/4}% Notes on June 10, 2009 at 97.093% of principal amount, for an initial yield to maturity of 12.375%, in an underwritten offering registered under the Securities Act of 1933, as amended (“1933 Act”). Net offering proceeds, after deducting underwriters’ discounts and estimated offering expenses but before giving effect to the underwriters’ reimbursement of up to \$0.5 million for offering expenses, were approximately \$284.8 million. We used net offering proceeds (before deducting estimated offering expenses) to repay debt under our bank credit facility. The 11^{3/4}% Notes were issued under an Indenture among Mariner, the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (the “Base Indenture”), as amended and supplemented by the First Supplemental Indenture thereto among the same parties, each dated as of June 10, 2009. Pursuant to the Base Indenture, we may issue multiple series of debt securities from time to time.

The Notes are governed by indentures that are substantially identical for each series. The Notes are senior unsecured obligations of Mariner, rank senior in right of payment to any future subordinated indebtedness, rank equally in right of payment with each other and with our existing and future senior unsecured indebtedness, and are effectively subordinated in right of payment to our senior secured indebtedness, including our obligations under our bank credit facility, to the extent of the collateral securing such indebtedness, and to all existing and future indebtedness and other liabilities of any non-guarantor subsidiaries.

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 senior in right of payment to any future subordinated indebtedness of the guarantor subsidiary, ranks equally in right of payment to all existing and future senior unsecured indebtedness

of the guarantor subsidiary and effectively subordinate to all existing and future secured indebtedness of the guarantor subsidiary, including its guarantees of indebtedness under our bank credit facility, to the extent of the collateral securing such indebtedness.

The 11^{3/4}% Notes mature on June 30, 2016 with interest payable on June 30 and December 30 of each year beginning December 30, 2009. The 8% Notes mature on May 15, 2017 with interest payable on May 15 and November 15 of each year. The 7^{1/2}% Notes mature on April 15, 2013 with interest payable on April 15 and October 15 of each year. There is no sinking fund for the Notes.

We may redeem the 11^{3/4}% Notes at any time before June 30, 2013, the 8% Notes at any time before May 15, 2012 and the 7^{1/2}% Notes at any time before April 15, 2010, in each case at a price equal to the principal amount redeemed plus a make-whole premium, using a discount rate of the Treasury rate plus 0.50% and accrued but unpaid interest. Beginning on the dates indicated below, we may redeem the Notes from time to time, in whole or in part, at the prices set forth below (expressed as percentages of the principal amount redeemed) plus accrued but unpaid interest:

<u>11^{3/4}% Notes</u>	<u>8% Notes</u>	<u>7^{1/2}% Notes</u>
June 30, 2013 at 105.875%	May 15, 2012 at 104.000%	April 15, 2010 at 103.750%
June 30, 2014 at 102.938%	May 15, 2013 at 102.667%	April 15, 2011 at 101.875%
June 30, 2015 and after at 100.000%	May 15, 2014 at 101.333%	April 15, 2012 and after at 100.000%
	May 15, 2015 and after at 100.000%	

In addition, before June 30, 2012, we may redeem up to 35% of the 11^{3/4}% Notes with the proceeds of equity offerings at a price equal to 111.750% of the principal amount of the 11^{3/4}% Notes redeemed plus accrued but unpaid interest. Before May 15, 2010, we may redeem up to 35% of the 8% Notes with the proceeds of equity offerings at a price equal to 108% of the principal amount of the 8% Notes redeemed plus accrued but unpaid interest.

If a change of control triggering event (as defined in each of the indentures governing the Notes) occurs, subject to certain exceptions, we must give holders of the Notes the opportunity to sell to us their Notes, in whole or in part, at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest and liquidated damages to the date of purchase.

We and our restricted subsidiaries are subject to certain negative covenants under each of the indentures governing the Notes. The indentures limit the ability of us and each of our restricted subsidiaries to, among other things:

- 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 its assets;
- engage in transactions with affiliates;
- pay dividends or make other distributions on capital stock or subordinated indebtedness; and
- create unrestricted subsidiaries.

Costs associated with the 11^{3/4}% Notes offering were approximately \$5.9 million, excluding discounts of \$8.7 million. Costs associated with the 8% Notes offering included aggregate underwriting discounts of approximately \$5.3 million and offering expenses of approximately \$1.3 million. Costs associated with the 7^{1/2}% Notes offering were approximately \$8.5 million, excluding discounts of \$3.8 million.

Common Stock Offering — On June 10, 2009, we sold and issued 11.5 million shares of our common stock at a public offering price of \$14.50 per share in an underwritten offering registered under the 1933 Act. The total sold includes 1.5 million shares issued upon full exercise of the underwriters' over-allotment option. Net offering proceeds, after deducting underwriters' discounts and estimated offering expenses but before giving effect to the underwriters' reimbursement of up to \$0.5 million for offering expenses, were approximately \$159.2 million. We used net offering proceeds (before deducting estimated offering expenses of approximately \$0.5 million) to repay debt under our bank credit facility.

Future Uses of Capital. Our identified needs for liquidity in the future are as follows:

- funding future capital expenditures;
- funding hurricane repairs and hurricane-related abandonment operations;
- financing any future acquisitions that we may identify;
- paying routine operating and administrative expenses; and
- paying other commitments comprised largely of cash settlement of hedging obligations and debt service.

2010 Capital Expenditures.

We anticipate that our base operating capital expenditures for 2010 will be approximately \$660.0 million (excluding hurricane-related expenditures and acquisitions), with significant potential for increase or decrease depending upon drilling success, acquisition opportunities and cash flow during the year. Approximately 67% of the base operating capital program is planned to be allocated to development activities, 26% to exploration activities, and the remainder to other items (primarily capitalized overhead and interest). In addition, we estimate to incur additional hurricane-related costs of \$44.5 million during 2010 related to Hurricane Ike, that we believe is substantially covered under applicable insurance. Complete recovery or settlement is not expected to occur during the next 12 months.

Obligations and Commitments

Consolidated Contractual Obligations — The following table presents a summary of our consolidated contractual obligations and commercial commitments as of December 31, 2009:

	Payments Due By Period				
	Total	2010	2011-2012 (In thousands)	2013-2014	Thereafter
Debt obligations(1)	\$ 1,205,000	\$ —	\$ 305,000	\$ 300,000	\$ 600,000
Interest obligations(2)	501,434	92,120	174,734	124,973	109,607
Operating leases	19,841	2,620	5,089	4,201	7,931
Abandonment liabilities	417,887	54,915	105,214	51,844	205,914
Seismic obligations	7,933	6,929	1,004	—	—
Capital accrual obligations	140,941	140,941	—	—	—
OIL Theoretical					
Withdrawal(3)	48,000	11,040	24,493	12,467	—
Rig commitment	15,686	15,686	—	—	—
Other liabilities(4)	103,547	103,547	—	—	—
Total contractual cash commitments	<u>\$ 2,460,269</u>	<u>\$ 427,798</u>	<u>\$ 615,534</u>	<u>\$ 493,485</u>	<u>\$ 923,452</u>

(1) As of December 31, 2009, we had incurred debt obligations under our bank credit facility and the Notes.

(2) Interest obligations represent interest due on the bank credit facility and the Notes per annum. Future interest obligations under our bank credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 3.40% weighted average interest rate on amounts outstanding under our

bank credit facility as of December 31, 2009, our cash payments for interest would be \$10.4 million annually for 2010 through 2011 and \$0.9 million in 2012.

- (3) We have accrued approximately \$48.0 million as of December 31, 2009, for an insurance premium contingency related to our membership in OIL. As part of our membership, we are obligated to pay a withdrawal premium if we elect to withdraw from OIL. We do not anticipate withdrawing from OIL; however, due to the contingency, OIL calculates a potential withdrawal premium annually based on past losses and we accrue a liability for the potential premium.
- (4) Other liabilities include accrued LOE of \$21.3 million, accrued liabilities of \$15.2 million, gas balancing of \$9.7 million, oil and gas payable of \$38.8 million, accrued compensation of \$12.0 million, other G&A of \$3.3 million and other liabilities for \$3.2 million.

Adequacy of Capital Sources and Liquidity

Future Capital Resources. Our anticipated sources of liquidity in the future are as follows:

- cash flow from operations in future periods;
- proceeds under our bank credit facility;
- proceeds from insurance policies relating to hurricane repairs; and
- proceeds from future capital markets transactions as needed.

Historically, we generally have tailored our operating capital program (exclusive of hurricane-related expenditures and acquisitions) within our projected operating cash flow so that our operating capital requirements were largely self-funding. In 2010, we anticipate that this program will exceed our projected operating cash flow due primarily to accelerated development of our long-lived, oily Permian Basin properties, and development of two deepwater discoveries and our unconventional resource portfolio. Based on our current operating plan and assumed price case, our expected cash flow from operations and continued access to our bank credit facility allows us ample liquidity to conduct our operations as planned for the foreseeable future. We generally expect to fund future acquisitions on a case by case basis through a combination of bank debt and capital markets activities.

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. 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 bank credit facility are largely dependent on our level of estimated proved reserves and current oil and natural gas prices. If either our estimated proved reserves or commodity prices decrease, amounts available to us to borrow under our bank credit facility could be reduced. If our cash flows are less than anticipated or amounts available for borrowing are reduced, we may be forced to defer planned capital expenditures.

In addition, the recent worldwide financial and credit crisis may adversely affect our liquidity. We may be unable to obtain adequate funding under our bank credit facility because our lending counterparties may be unwilling or unable to meet their funding obligations, or because our borrowing base under the facility may be decreased as the result of a redetermination, reducing it due to lower oil or natural gas prices, operating difficulties, declines in reserves or other reasons. If funding is not available as needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our business strategies or otherwise take advantage of business opportunities or respond to competitive pressures.

Off-Balance Sheet Arrangements

Our bank credit facility has a letter of credit subfacility of up to \$50.0 million that is included as a use of the borrowing base. As of December 31, 2009, four such letters of credit totaling \$4.7 million were outstanding.

Fair Value Measurement

We determine the fair value of our natural gas and crude oil fixed price swaps by reference to forward pricing curves for natural gas and oil futures contracts. The difference between the forward price curve and the contractual fixed price is discounted to the measurement date using a credit-risk adjusted discount rate. The credit risk adjustment for swap liabilities is based on our credit quality and the credit risk adjustment for swap assets is based on the credit quality of our counterparty. Our fair value determinations of our swaps have historically approximated our exit price for such derivatives.

We have determined that the fair value methodology described above for our swaps is consistent with observable market inputs and have categorized our swaps as Level 2 in accordance with accounting for fair value measurements and disclosures under GAAP.

During the twelve months ended December 31, 2009, we recorded a net liability for the decrease in the fair value of our derivative financial instruments of \$161.5 million, principally due to the increase in natural gas and oil commodity prices above our swap prices. The decrease was comprised of a decrease in accumulated other comprehensive income of approximately \$253.7 million, net of income taxes of \$140.8 million, approximately \$173.7 million of favorable cash hedging settlements and a \$58.7 million gain on liquidated swaps during the period reflected in natural gas and oil revenues and an unrealized non-cash gain due to hedging ineffectiveness under GAAP of approximately \$0.3 million reflected in natural gas revenues.

We expect the continued volatility of natural gas and oil commodity prices to have a material impact on the fair value of our derivatives positions. It is our intent to hold all of our derivatives positions to maturity such that realized gains or losses are generally recognized in income when the hedged natural gas or oil is produced and sold. While the derivatives settlements may decrease (or increase) our effective price realized, the ultimate settlement of our derivatives positions is not expected to materially adversely affect our liquidity, results of operations or cash flows.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon Consolidated Financial Statements that have been prepared in accordance with GAAP. The preparation of these Consolidated 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 Consolidated Financial Statements. See Note 1 "Summary of Significant Accounting Policies" in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Annual Report on Form 10-K. We analyze our estimates, including those related to oil and gas revenues; oil and gas properties; fair value of derivative instruments; goodwill; abandonment liabilities; income taxes; commitments and contingencies; depreciation, depletion and amortization; share-based compensation; and full cost ceiling calculation. Our estimates are based on historical experience and various 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 Consolidated Financial Statements.

Oil and Gas Properties

Our 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, including certain G&A costs. G&A costs associated with production, operations, marketing and general corporate activities are expensed as incurred. The capitalized costs, coupled with our estimated asset retirement obligations recorded in accordance with accounting for asset retirement and environmental obligations under GAAP, are included in the amortization base and amortized to expense using the unit-of-production method. Amortization is calculated based on estimated proved oil and gas reserves. Proceeds from the sale or disposition of oil and gas properties are applied to reduce net capitalized costs

unless the sale or disposition causes a significant change in the relationship between costs and the estimated value of proved reserves.

Full Cost Ceiling Test

Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and gas properties are subject to a ceiling. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. The natural gas and oil prices used to calculate the full cost ceiling limitation are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, adjusted for "basis" or location differentials. Price is held constant over the life of the reserves.

We use derivative financial instruments that qualify for cash flow hedge accounting under accounting for derivative instruments and hedging activities under GAAP to hedge against the volatility of oil and natural gas prices. In accordance with SEC guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. If net capitalized costs related to proved properties exceed the ceiling limit, the excess is impaired and recorded in the Consolidated Statements of Operations.

At December 31, 2009, the net capitalized cost of proved oil and gas properties exceeded the ceiling limit and we recorded an impairment of \$49.6 million (\$31.9 million, net of tax). The impairment would have been \$159.2 million (\$102.3 million, net of tax) if we had not used hedge adjusted prices for the volumes that were subject to hedges. This impairment is due primarily to a decline in the 12-month average oil and gas commodity prices used from January 1, 2009 through December 1, 2009 as compared to the spot prices utilized at March 31, 2009 and December 31, 2008 when we recorded non-cash ceiling test impairments of \$704.7 million (\$454.6 million, net of tax) and \$575.6 million (\$369.1 million, net of tax), respectively. The ceiling limit of our proved reserves was calculated at December 31, 2009 based upon 12-month average market prices of \$3.87 per Mcf for gas and \$61.18 per barrel for oil, adjusted for market differentials. At March 31, 2009 and December 31, 2008, the ceiling limit of our proved reserves was calculated based on quoted market spot prices of \$3.63 and \$5.71 per Mcf for gas and \$49.65 and \$44.61 per barrel for oil, respectively, adjusted for market differentials. At December 31, 2007 the ceiling limit exceeded the net capitalized costs of our proved oil and gas properties and no impairment was recorded. We may be required to recognize additional non-cash impairment charges in future reporting periods if the average 12-month market prices for oil and natural gas were to decline. At December 31, 2009, we had 48,697,000 MMbtus of natural gas and 3,815,500 Bbls of oil of future production hedged.

Estimated Proved Reserves

Our most significant financial estimates are based on estimates of proved oil and natural gas reserves. Estimates of proved reserves are key components in determining 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. 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 Company, L.P.

Unproved Properties

Costs associated with unproved properties and properties under development are excluded from the full cost amortization base until the properties have been evaluated. Additionally, the costs associated with seismic data, leasehold acreage, wells currently drilling and capitalized interest are also initially excluded from the amortization base. Unevaluated leasehold costs are either transferred to the amortization base once evaluation is complete or the lease expires on leasehold acreage. Until that time, the costs are subject to impairment,

which is assessed quarterly. Leasehold costs are transferred to the amortization base to the extent a property is determined to be impaired. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from the amortization base. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

The decision to withhold costs from the amortization base and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2009, we had a total of approximately \$292.2 million of costs excluded from the amortization base of our full cost pools. Because the application of the full cost ceiling test at December 31, 2009 resulted in an excess of the carrying value of oil and gas properties over the ceiling limit, inclusion of some or all of our unevaluated property costs in the amortization base, without adding any associated reserves, would have resulted in a larger ceiling test impairment.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review these assumptions and estimates of future development and abandonment costs on an annual basis, or more frequently if an event occurs or circumstances change that would affect our assumptions and estimates.

DD&A

Our rate for recording DD&A is dependent upon estimates of our proved reserves, future development and abandonment costs and capital spending. If the estimates of proved reserves decline, the rate at which we record DD&A expense increases, reducing our net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the full cost ceiling test. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expense. We are unable to predict changes in future development costs as such costs are dependent on the success of our development program, as well as future economic conditions.

Abandonment Liability

In accordance with accounting for asset retirement and environmental obligations under GAAP, we record the fair value of a liability for the legal obligation to retire an asset in the period in which it is incurred and capitalize the corresponding cost by increasing the carrying amount of the related long-lived asset. Upon adoption, we recorded an asset retirement obligation to reflect our legal obligations related to future plugging and abandonment of our oil and natural gas wells. The liability is accreted to its then present value each period, and the capitalized cost, net of salvage, is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recognized in Oil and Gas Properties.

To estimate the fair value of an asset retirement obligation, we employ a present value technique, which reflects certain assumptions, including our credit-adjusted risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Goodwill

We account for goodwill in accordance with GAAP which requires goodwill to be tested for impairment on an annual basis and between annual tests when events or circumstances indicate a potential impairment. In a purchase transaction, goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed. We follow the full cost method of accounting and all of our oil and gas properties are located in the United States. For the purpose of performing an impairment test, we have determined that we have one reporting unit. Our goodwill impairment reviews consist of a two-step process. The first step is to determine the fair value of our reporting unit and compare it to the carrying value of the related net assets. Fair value is determined based on our estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write-down is required. The second step is required if the fair value of the reporting unit is less than the carrying value of the net assets. In this step the implied fair value of the reporting unit is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written-down to its implied fair value.

We perform our goodwill test annually on November 30 and more often if circumstances require. At November 30, 2008, we had \$295.6 million in goodwill. In connection with our annual impairment test on November 30, 2008, we performed a step one impairment analysis. As a result of weakened economic conditions and a decline in our stock price during the fourth quarter 2008, the carrying value of our reporting unit exceeded the fair value of our net assets and a step two analysis was required to determine the impairment. Our fair value estimates in step two were developed using a weighted average cost of capital ("WACC") of 12.0% and a control premium of 25.0%. A 1.0% increase and decrease of the WACC would have changed the fair value by (3.7%) and 4.0% respectively. We allocated the estimated fair value determined using these assumptions to the identifiable tangible and intangible assets and liabilities of our reporting unit based on their respective values. This allocation indicated no residual value for goodwill and we recorded \$295.6 million of goodwill impairment in continuing operations as of December 31, 2008. We had previously determined that there was no impairment loss in continuing operations as of December 31, 2007 and 2006, respectively. In 2007, goodwill decreased as a result of changes in the book and tax basis related to a merger transaction consummated in March 2006. There was no remaining balance of goodwill in 2009 to assess for impairment.

Income Taxes

Our provision for taxes includes both state and federal taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP 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 basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results

of operations and cash flows. We do not have uncertain tax positions outstanding and, as such, did not record a liability for the years ended December 31, 2009 and 2008.

Derivative Financial Instruments

We utilize derivative instruments 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 and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as cash flow hedges in accordance with accounting for derivatives and hedging under GAAP. Gains and losses resulting from these transactions, recorded at market value, are deferred and recorded in Accumulated Other Comprehensive Income as appropriate, until recognized as operating income in our Consolidated Statements of Operations as the physical production hedged by the contracts is delivered. We present the fair value of our derivatives on a net basis in accordance with GAAP.

We are required to assess the effectiveness of all our derivative contracts at inception and at every quarter-end. If open contracts cease to qualify for hedge accounting, mark-to-market accounting is utilized and changes in the fair value of open contracts are recognized in the Consolidated Statements of Operations. Mark-to-market accounting may cause volatility in Net Income. Fair value is assessed, measured and estimated by obtaining forward commodity pricing, credit adjusted risk-free interest rates and estimated volatility factors. In addition, forward price curves and estimates of future volatility factors are used to assess and measure the effectiveness of our open contracts at the end of each period. The fair values we report in our Consolidated 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.

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 us to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

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

Revenue Recognition

We recognize oil and natural gas revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when persuasive evidence of an arrangement exists, delivery has occurred and title has transferred, the seller's price to the buyer is fixed or determinable and collectability is reasonably assured.

When we have an interest with other producers in properties from which natural gas is produced, we use the entitlement method to account for any imbalances. Imbalances occur when we sell more or less product than we are entitled to under our ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that we sell in excess of our entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount we sell is recognized as revenue and a receivable is accrued.

Share-Based Compensation Expense

We account for share-based compensation in accordance with the fair value recognition provisions of accounting for stock compensation under GAAP. Under those fair value recognition provisions, share-based compensation cost is measured at the grant date based on the calculated fair value of the award and is recognized as expense over the vesting period. We use the Black-Scholes option pricing model to determine the fair value of options on the grant date, which requires judgment in estimating the expected life of the option and the expected volatility of our stock. We use a Monte Carlo simulation to estimate the fair value of restricted stock granted in 2008 under our stock incentive plan's long-term performance-based restricted stock program.

Recent Accounting Pronouncements

In February 2010, the Financial Accounting Standards Board issued authoritative guidance which requires additional information to be disclosed principally in respect of Level 3 fair value measurements and transfers to and from Level 1 and Level 2 measurements. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 fair value measurements. The guidance is generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. We are currently evaluating the potential impact of adoption.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Prices and Related Hedging Activities

Our major market risk exposure continues to be the prices applicable to our natural gas and oil production. The sales price of our production is primarily driven by the prevailing market price. Historically, prices received for our natural gas and oil production have been volatile and unpredictable. Hypothetically, if production levels were to remain at 2009 levels, a 10% increase in commodity prices from those as of December 31, 2009 would increase our cash flow by approximately \$68.4 million for the year ended December 31, 2010.

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. In an effort to reduce the effects of the volatility of the price of oil and natural gas on our operations, management has adopted a policy of hedging oil and natural gas prices from time to time primarily through the use of commodity price swap agreements and costless collar arrangements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. 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 oil and natural gas revenue in the Consolidated Statements of Operations. Not qualifying for hedge accounting and cash flow hedge designation will cause volatility in Net Income. The fair values we report in our Consolidated 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.

During 2009, the Company liquidated certain natural gas and crude oil fixed price swaps that previously had been designated as cash flow hedges for accounting purposes in respect of 10,205,560 MMBtu of natural gas and 977,000 Bbls of crude oil. The Company received \$58.7 million in conjunction with these liquidations and recognized natural gas and oil revenues of \$35.3 million and \$23.4 million, respectively.

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Derivative gains and losses are recorded by commodity type in oil and natural gas revenues in the Consolidated Statements of Operations. The effects on our oil and gas revenues from our hedging activities were as follows:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Cash Gain (Loss) on Settlements(1)	\$ 173,684	\$ (98,814)	\$ 46,732
Gain (Loss) on Hedge Ineffectiveness(1)(2)	264	(1,995)	(1,655)
Reclassification of Liquidated Swaps(3)	58,710	—	—
Total	<u>\$ 232,658</u>	<u>\$ (100,809)</u>	<u>\$ 45,077</u>

- (1) Designated as cash flow hedges pursuant to accounting for derivatives and hedging under GAAP.
- (2) Unrealized loss recognized in natural gas revenue related to the ineffective portion of open contracts that are not eligible for deferral under GAAP due primarily to the basis differentials between the contract price and the indexed price at the point of sale.
- (3) Natural gas and crude oil fixed price swaps liquidated in the first and third quarter 2009 that do not qualify for hedge accounting. These amounts include net losses of \$2.8 million for the year ended December 31, 2009.

As of December 31, 2009, the Company had the following hedging contracts outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price (In thousands)	Fair Value Asset/(Liability)
Natural Gas (MMbtus)			
January 1 — December 31, 2010	22,619,000	\$ 5.88	\$ 2,239
January 1 — December 31, 2011	13,650,000	\$ 6.45	1,540
January 1 — December 31, 2012	6,588,000	\$ 6.62	497
January 1 — December 31, 2013	5,840,000	\$ 6.76	410
Crude Oil (Bbls)			
January 1 — December 31, 2010	1,934,500	\$ 67.48	(27,708)
January 1 — December 31, 2011	978,100	\$ 73.24	(11,309)
January 1 — December 31, 2012	494,100	\$ 80.77	(3,058)
January 1 — December 31, 2013	408,800	\$ 82.81	(2,195)
Total			<u>\$ (39,584)</u>

As of December 31, 2008, the Company had the following hedging activity outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price (In thousands)	Fair Value Asset/(Liability)
Natural Gas (MMbtus)			
January 1 — December 31, 2009	31,642,084	\$ 8.48	\$ 74,709
Crude Oil (Bbls)			
January 1 — December 31, 2009	2,172,210	\$ 76.15	47,220
Total			<u>\$ 121,929</u>

We have reviewed the financial strength of our counterparties and believe the credit risk associated with these swaps to be minimal. Hedges with counterparties that are lenders under our bank credit facility are secured under the bank credit facility.

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As of December 31, 2009, we expect to realize within the next 12 months approximately \$25.5 million in net losses resulting from hedging activities currently recorded in accumulated other comprehensive income. The net hedging loss is expected to be realized as a decrease of \$27.7 million to oil revenues and an increase of \$2.2 million to natural gas revenues.

Interest Rate Market Risk

Borrowings under our bank credit facility mature on January 31, 2012 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. At December 31, 2009, the blended interest rate on our outstanding bank debt was 3.40%. If the balance of our bank debt at December 31, 2009 were to remain constant, a 10% increase in market interest rates would decrease our cash flow by approximately \$1.0 million for the year ended December 31, 2010.

Item 8. Financial Statements and Supplementary Data.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including Mariner's chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting for Mariner. Mariner's internal control system was designed to provide reasonable assurance to Mariner's management and directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Mariner's internal control over financial reporting was effective as of December 31, 2009. Management excluded from its evaluation the internal control over financial reporting of the subsidiaries of Edge Petroleum Corporation (the "Edge Subsidiaries") which Mariner acquired on December 31, 2009. The total assets of the Edge Subsidiaries as of December 31, 2009 constituted approximately 11% of Mariner's total assets as of December 31, 2009. Deloitte & Touche LLP, Mariner's independent auditor for 2009, has issued an attestation report on Mariner's internal control over financial reporting that is included in the accompanying Report of Independent Registered Public Accounting Firm.

/s/

Scott D. Josey

Scott D. Josey,
Chairman of the Board,
Chief Executive Officer and President

/s/

Jesus G. Melendrez

Jesus G. Melendrez,
Senior Vice President, Chief Commercial Officer,
Acting Chief Financial Officer and Treasurer

Houston, Texas
March 1, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Mariner Energy, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Mariner Energy, Inc. and subsidiaries (the “Company”) as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2009. We also have audited the Company’s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management’s Report on Internal Control over Financial Reporting (“Report of Management”), management excluded from its evaluation the internal control over financial reporting of the subsidiaries of Edge Petroleum Corporation (the “Edge Subsidiaries”) which the Company acquired on December 31, 2009. The total assets of the Edge Subsidiaries as of December 31, 2009 constituted approximately 11% of the total assets of the Company as of December 31, 2009. Accordingly, our audit did not include the internal control over financial reporting of the Edge Subsidiaries. The Company’s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management. Our responsibility is to express an opinion on these financial statements and an opinion on the Company’s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become

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inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mariner Energy, Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1 to the consolidated financial statements, on December 31, 2009, the Company adopted Accounting Standards Update No. 2010-3, “*Oil and Gas Reserve Estimation and Disclosures*” and Accounting Standards Codification Topic 805, “*Business Combinations*”.

/S/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010

MARINER ENERGY, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except share data)	
Current Assets:		
Cash and cash equivalents	\$ 8,919	\$ 3,251
Receivables, net of allowances of \$3,408 and \$3,868, respectively	148,725	219,920
Insurance receivables	8,452	13,123
Derivative financial instruments	2,239	121,929
Intangible assets	22,615	2,353
Prepaid expenses and other	11,667	14,377
Deferred income tax	9,704	—
Total current assets	212,321	374,953
Property and Equipment:		
Proved oil and gas properties, full cost method	5,117,273	4,448,146
Unproved properties, not subject to amortization	292,237	201,121
Total oil and gas properties	5,409,510	4,649,267
Other property and equipment	55,695	53,115
Accumulated depreciation, depletion and amortization:		
Proved oil and gas properties	(2,884,411)	(1,767,028)
Other properties	(8,235)	(5,477)
Total accumulated depreciation, depletion and amortization	(2,892,646)	(1,772,505)
Total property and equipment, net	2,572,559	2,929,877
Insurance Receivables	—	22,132
Derivative Financial Instruments	902	—
Deferred Income Tax	12,491	—
Other Assets, net of amortization	68,932	65,831
TOTAL ASSETS	\$ 2,867,205	\$ 3,392,793
Current Liabilities:		
Accounts payable	\$ 3,579	\$ 3,837
Accrued liabilities	137,206	107,815
Accrued capital costs	140,941	195,833
Deferred income tax	—	23,148
Abandonment liability	54,915	82,364
Accrued interest	8,262	12,567
Derivative financial instruments	27,708	—
Total current liabilities	372,611	425,564
Long-Term Liabilities:		
Abandonment liability	362,972	325,880
Deferred income tax	—	319,766
Derivative financial instruments	15,017	—
Long-term debt	1,194,850	1,170,000
Other long-term liabilities	38,800	31,263
Total long-term liabilities	1,611,639	1,846,909
Commitments and Contingencies (see Note 8)		
Stockholders' Equity:		
Preferred stock, \$.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2009 and December 31, 2008	—	—
Common stock, \$.0001 par value; 180,000,000 shares authorized, 101,806,825 shares issued and outstanding at December 31, 2009; 180,000,000 shares authorized, 88,846,073 shares issued and outstanding at December 31, 2008	10	9
Additional paid-in-capital	1,257,526	1,071,347
Accumulated other comprehensive (loss) income	(25,955)	78,181
Accumulated deficit	(348,626)	(29,217)
Total stockholders' equity	882,955	1,120,320
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 2,867,205	\$ 3,392,793

*The accompanying Notes to the Consolidated Financial Statements
are an integral part of these financial statements*

MARINER ENERGY, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
(In thousands except share data)			
Revenues:			
Natural gas	\$ 552,259	\$ 742,370	\$ 534,537
Oil	315,642	419,878	284,405
Natural gas liquids	48,921	85,715	54,192
Other revenues	26,119	52,544	1,631
Total revenues	<u>942,941</u>	<u>1,300,507</u>	<u>874,765</u>
Costs and Expenses:			
Lease operating expense	249,449	231,645	152,627
Severance and ad valorem taxes	14,410	18,191	13,101
Transportation expense	18,494	14,996	8,794
General and administrative expense	79,960	60,613	42,151
Depreciation, depletion and amortization	399,400	467,265	384,321
Full cost ceiling test impairment	754,325	575,607	—
Goodwill impairment	—	295,598	—
Other property impairment	—	15,252	—
Other miscellaneous expense	8,306	3,052	5,061
Total costs and expenses	<u>1,524,344</u>	<u>1,682,219</u>	<u>606,055</u>
OPERATING (LOSS) INCOME	(581,403)	(381,712)	268,710
Other Income/(Expenses):			
Interest income	499	1,362	1,403
Interest expense, net of amounts capitalized	(70,134)	(56,398)	(54,665)
Gain on acquisition	107,259	—	—
Other income	—	—	5,811
(Loss) Income Before Taxes	(543,779)	(436,748)	221,259
Benefit (Provision) for Income Taxes	224,370	48,223	(77,324)
Net (Loss) Income	(319,409)	(388,525)	143,935
Less: Net income attributable to noncontrolling interest	—	(188)	(1)
NET (LOSS) INCOME ATTRIBUTABLE TO MARINER ENERGY, INC	<u>\$ (319,409)</u>	<u>\$ (388,713)</u>	<u>\$ 143,934</u>
Net (Loss) Income per share attributable to Mariner Energy, Inc.:			
Basic	\$ (3.34)	\$ (4.44)	\$ 1.68
Diluted	\$ (3.34)	\$ (4.44)	\$ 1.67
Weighted average shares outstanding:			
Basic	95,607,445	87,491,385	85,645,199
Diluted	95,607,445	87,491,385	86,125,811

The accompanying Notes to the Consolidated Financial Statements are an integral part of these financial statements

MARINER ENERGY, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock	Stock Amount	Additional Paid-In-Capital	Accumulated Other Comprehensive Income/(Loss)	Accumulated Retained Earnings (Deficit) (In thousands)	Total Mariner Energy, Inc. Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
Balance at December 31, 2006	86,376	\$ 9	\$ 1,043,923	\$ 43,097	\$ 215,562	\$ 1,302,591	\$ —	\$ 1,302,591
Common shares issued — restricted stock	906	—	—	—	—	—	—	—
Treasury stock bought and cancelled on same day	(72)	—	(1,553)	—	—	(1,553)	—	(1,553)
Forfeiture of restricted stock	(45)	—	(907)	—	—	(907)	—	(907)
Share-based compensation	—	—	11,797	—	—	11,797	—	11,797
Stock options exercised	64	—	829	—	—	829	—	829
Comprehensive income (loss):								
Net income	—	—	—	—	143,934	143,934	1	143,935
Change in fair value of derivative hedging instruments — net of income taxes of (\$52,385)	—	—	—	(94,935)	—	(94,935)	—	(94,935)
Hedge settlements reclassified to income — net of income taxes of \$15,815	—	—	—	29,262	—	29,262	—	29,262
Total comprehensive (loss) income	—	—	—	(65,673)	143,934	78,261	1	78,262
Balance at December 31, 2007	87,229	\$ 9	\$ 1,054,089	\$ (22,576)	\$ 359,496	\$ 1,391,018	\$ 1	\$ 1,391,019
Common shares issued — restricted stock	1,734	—	—	—	—	—	—	—
Treasury stock bought and cancelled on same day	(144)	—	(4,313)	—	—	(4,313)	—	(4,313)
Forfeiture of restricted stock	(29)	—	—	—	—	—	—	—
Share-based compensation	—	—	20,829	—	—	20,829	—	20,829
Stock options exercised	56	—	742	—	—	742	—	742
Comprehensive income (loss):								
Net loss	—	—	—	—	(388,713)	(388,713)	188	(388,525)
Change in fair value of derivative hedging instruments — net of income taxes of \$91,316	—	—	—	165,675	—	165,675	—	165,675
Hedge settlements reclassified to income — net of income taxes of (\$35,891)	—	—	—	(64,918)	—	(64,918)	—	(64,918)
Total comprehensive income (loss)	—	—	—	100,757	(388,713)	(287,956)	188	(287,768)
Purchase of noncontrolling interest	—	—	—	—	—	—	(189)	(189)
Balance at December 31, 2008	88,846	\$ 9	\$ 1,071,347	\$ 78,181	\$ (29,217)	\$ 1,120,320	\$ —	\$ 1,120,320
Common shares issued — equity offering	11,500	1	159,734	—	—	159,735	—	159,735
Common shares issued — restricted stock	1,742	—	—	—	—	—	—	—
Treasury stock bought and cancelled on same day	(216)	—	(2,666)	—	—	(2,666)	—	(2,666)
Forfeiture of restricted stock	(66)	—	—	—	—	—	—	—
Share-based compensation	—	—	29,097	—	—	29,097	—	29,097
Stock options exercised	1	—	14	—	—	14	—	14
Comprehensive loss:								
Net loss	—	—	—	—	(319,409)	(319,409)	—	(319,409)
Change in fair value of derivative hedging instruments — net of income taxes of (\$140,778)	—	—	—	(253,658)	—	(253,658)	—	(253,658)
Hedge settlements reclassified to income — net of income taxes of \$83,129	—	—	—	149,529	—	149,529	—	149,529
Foreign currency translation adjustment	—	—	—	(7)	—	(7)	—	(7)
Total comprehensive loss	—	—	—	(104,136)	(319,409)	(423,545)	—	(423,545)
Balance at December 31, 2009	101,807	\$ 10	\$ 1,257,526	\$ (25,955)	\$ (348,626)	\$ 882,955	\$ —	\$ 882,955

The accompanying Notes to the Consolidated Financial Statements are an integral part of these financial statements

MARINER ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Operating Activities:			
Net (loss) income attributable to Mariner Energy, Inc.	\$ (319,409)	\$ (388,713)	\$ 143,934
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Deferred income tax	(224,370)	(49,403)	77,324
Depreciation, depletion and amortization	399,400	467,265	384,321
Ineffectiveness of derivative instruments	(264)	1,995	1,655
Full cost ceiling test impairment	754,325	575,607	—
Goodwill impairment	—	295,598	—
Other property impairment	—	15,252	—
Gain on acquisition	(107,259)	—	—
Share-based compensation	25,434	21,017	10,890
Other	3,292	(52,731)	4,487
Changes in operating assets and liabilities:			
Receivables	79,950	(63,015)	(9,805)
Insurance receivables	26,803	47,839	(22,606)
Prepaid expenses and other	(23,777)	(1,853)	(23,406)
Accounts payable and accrued liabilities	(36,458)	(6,841)	(30,680)
Net cash provided by operating activities	<u>577,667</u>	<u>862,017</u>	<u>536,114</u>
Investing Activities:			
Acquisitions and additions to oil and gas properties	(530,949)	(1,220,067)	(674,740)
Acquisition of subsidiaries of Edge Petroleum Corporation	(213,553)	—	—
Additions to other property and equipment	(2,606)	(49,717)	—
Property conveyances	—	—	4,130
Restricted cash designated for investment	—	5,000	26,830
Net cash used in investing activities	<u>(747,108)</u>	<u>(1,264,784)</u>	<u>(643,780)</u>
Financing Activities:			
Credit facility borrowings	710,221	1,268,000	564,000
Credit facility repayments	(975,221)	(877,000)	(739,000)
Proceeds from note offering	291,279	—	300,000
Proceeds from equity offering	159,735	—	—
Debt redetermination costs	(2,346)	—	—
Repurchase of stock	(2,666)	(4,313)	(1,553)
Proceeds from exercise of stock options	14	742	829
Deferred offering costs	(5,907)	—	(6,600)
Partner distributions	—	—	(1,000)
Net cash provided by financing activities	<u>175,109</u>	<u>387,429</u>	<u>116,676</u>
Increase (Decrease) in Cash and Cash Equivalents	<u>5,668</u>	<u>(15,338)</u>	<u>9,010</u>
Cash and Cash Equivalents at Beginning of Period	<u>3,251</u>	<u>18,589</u>	<u>9,579</u>
Cash and Cash Equivalents at End of Period	<u>\$ 8,919</u>	<u>\$ 3,251</u>	<u>\$ 18,589</u>

*The accompanying Notes to the Consolidated Financial Statements
are an integral part of these financial statements*

MARINER ENERGY, INC.

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2009, 2008 and 2007**

Note 1. Summary of Significant Accounting Policies

Mariner Energy, Inc. (“Mariner” or “the Company”) is an independent oil and gas exploration, development and production company with principal operations in the Permian Basin, in the Gulf Coast and in the Gulf of Mexico, both shelf and deepwater. Unless otherwise indicated, references to “Mariner”, “the Company”, “we”, “our”, “ours” and “us” refer to Mariner Energy, Inc. and its subsidiaries collectively.

Principles of Consolidation — The Consolidated Financial Statements include Mariner’s accounts and those of its subsidiaries. All intercompany transactions are eliminated upon consolidation.

Reclassifications and Use of Estimates in the Preparation of Financial Statements — Certain prior period amounts have been reclassified to conform to current year presentation. Amounts for litigation expense were presented as “Other miscellaneous expense” in the Company’s Consolidated Statements of Operations for the year ended December 31, 2007. These amounts are presented herein as “General and administrative expense” for comparability to 2009 and 2008 presentation. Other reclassifications are insignificant in nature. These reclassifications had no effect on total operating income or net income.

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (“GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from these estimates.

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

Receivables — Substantially all of the Company’s receivables arise from sales of oil or natural gas, or from reimbursable expenses billed to the other participants in oil and gas wells for which the Company serves as operator. The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated.

Insurance receivables — The Company records receivables related to insurance recoveries when it believes the amount of the claim is realizable. The balance at December 31, 2009 relates to both repair and capital-related costs incurred to bring productive properties back to operating condition after sustaining significant damage from Hurricane Ike in 2008. Any difference in the amount recovered from the insurance provider and the insurance receivable will be recorded as an adjustment to oil and gas properties when the amount relates to capital costs incurred and to lease operating expense (“LOE”) when the amount relates to repair costs incurred.

Oil and Gas Properties — The Company’s 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, including eligible general and administrative costs (“G&A”). G&A costs associated with production, operations, marketing and general corporate activities are expensed as incurred. These capitalized costs, coupled with its estimated asset retirement obligations recorded in accordance with accounting for asset retirement and environmental obligations under GAAP, are included in the amortization base and amortized to expense using the unit-of-production method. Amortization is calculated based on estimated proved oil and gas reserves. Proceeds from the sale or disposition of oil and gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated value of proved reserves. For the years ended

MARINER ENERGY, INC.**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007**

December 31, 2009 and 2008, capitalized G&A totaled \$21.2 million and \$19.8 million, respectively, of which \$3.6 million and \$3.0 million, respectively related to non-cash share-based compensation.

Full Cost Ceiling Test — Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and gas properties are subject to a full cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. In accordance with Securities and Exchange Commission (“SEC”) rules, the natural gas and oil prices used to calculate the full cost ceiling limitation are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Prices are adjusted for “basis” or location differentials. Price is held constant over the life of the reserves. The Company uses derivative financial instruments that qualify for cash flow hedge accounting under GAAP to hedge against the volatility of oil and natural gas prices. In accordance with SEC guidelines, Mariner includes estimated future cash flows from its hedging program in the ceiling test calculation. If net capitalized costs related to proved properties exceed the ceiling limit, the excess is impaired and recorded in the Consolidated Statements of Operations.

At December 31, 2009, the net capitalized cost of proved oil and gas properties exceeded the ceiling limit and Mariner recorded an impairment of \$49.6 million (\$31.9 million, net of tax). The impairment would have been \$159.2 million (\$102.3 million, net of tax) if the Company had not used hedge adjusted prices for the volumes that were subject to hedges. This impairment is due primarily to a decline in the 12-month average oil and gas commodity prices from January 1, 2009 through December 1, 2009 used as compared to the spot prices utilized at March 31, 2009 and December 31, 2008 when the Company recorded non-cash ceiling test impairments of \$704.7 million (\$454.6 million, net of tax) and \$575.6 million (\$369.1 million, net of tax), respectively. The ceiling limit of its proved reserves was calculated at December 31, 2009 based upon 12-month average market prices of \$3.87 per Mcf for gas and \$61.18 per barrel for oil, adjusted for market differentials. At March 31, 2009 and December 31, 2008, the ceiling limit of its proved reserves was calculated based on quoted market spot prices of \$3.63 and \$5.71 per Mcf for gas and \$49.65 and \$44.61 per barrel for oil, respectively, adjusted for market differentials. At December 31, 2007 the ceiling limit exceeded the net capitalized costs of the Company’s proved oil and gas properties and no impairment was recorded. The Company may be required to recognize additional non-cash impairment charges in future reporting periods if average 12-month market prices for oil and natural gas were to decline. At December 31, 2009, the Company had 48,697,000 MMBtus of natural gas and 3,815,500 Bbls of oil of future production hedged.

Unproved Properties — Costs associated with unproved properties and properties under development are excluded from the full cost amortization base until the properties have been evaluated. Additionally, the costs associated with seismic data, leasehold acreage, wells currently drilling and capitalized interest are also initially excluded from the amortization base. Unevaluated leasehold costs are either transferred to the amortization base once evaluation is complete or the lease expires on leasehold acreage. Until that time, the costs are subject to impairment which is assessed quarterly. Leasehold costs are transferred to the amortization base to the extent a property is determined to be impaired. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from the amortization base. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

MARINER ENERGY, INC.**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The decision to withhold costs from the amortization base and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including the Company's drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2009, the Company had a total of approximately \$292.2 million of costs excluded from the amortization base of the full cost pool. Because the application of the full cost ceiling test at December 31, 2009 resulted in an excess of the carrying value of oil and gas properties over the ceiling limit, inclusion of some or all of Mariner's unevaluated property costs in the amortization base, without adding any associated reserves, would have resulted in a larger ceiling test impairment.

Future Development and Abandonment Costs — Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of production platforms, gathering systems and related structures and restoration costs of land and seabed. The Company develops estimates of these costs for each of its properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The Company reviews these assumptions and estimates of future development and abandonment costs on an annual basis, or more frequently if an event occurs or circumstances change that would affect the assumptions and estimates.

Estimated Proved Reserves — The Company's most significant financial estimates are based on estimates of proved oil and natural gas reserves. Estimates of proved reserves are key components in determining the rate for recording depreciation, depletion and amortization and the Company's 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 the Company's control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering and production data. The accuracy of reserve estimates is a function of the quality and quantity of available data.

Depreciation, Depletion, and Amortization ("DD&A") — Mariner's rate for recording DD&A is dependent upon its estimate of proved reserves, future development and abandonment costs and capital spending. If the estimates of proved reserves decline, the rate at which the Company records DD&A expense increases, reducing its net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the full cost ceiling test. In addition, increases in costs required to develop the Company's reserves would increase the rate at which it records DD&A expense. Mariner is unable to predict changes in future development costs as such costs are dependent on the success of its development program, as well as future economic conditions.

Abandonment Liability — In accordance with accounting for asset retirement and environmental obligations under GAAP, the Company records the fair value of a liability for the legal obligation to retire an asset in the period in which it is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. Upon adoption, the Company recorded an asset retirement obligation to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells. 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, the difference is recognized in proved oil and gas properties.

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To estimate the fair value of an asset retirement obligation, the Company employs a present value technique, which reflects certain assumptions, including its credit-adjusted risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

The following roll forward is provided as a reconciliation of the beginning and ending aggregate carrying amounts of the asset retirement obligation.

	<u>2009</u>	<u>2008</u>
	(In thousands)	
Abandonment liability as of January 1	\$ 408,244	\$ 222,006
Liabilities incurred	23,842	46,514
Liabilities settled	(61,228)	(73,164)
Accretion expense	33,582	23,511
Revisions to previous estimates	7,992	144,957
Liabilities from assets acquired	5,455	44,420
Abandonment liability as of December 31(1)	<u>\$ 417,887</u>	<u>\$ 408,244</u>

(1) Includes \$54.9 million and \$82.4 million classified as a current accrued liability at December 31, 2009 and 2008.

Other Assets — Other assets at December 31, 2009 and 2008 were primarily comprised of the following:

	<u>2009</u>	<u>2008</u>
	(In thousands)	
Oil and gas lease and well equipment held in inventory	\$ 42,975	\$ 41,051
Debt issuance costs	13,602	13,439
Prepaid compression and other	5,850	6,907
Long term deposits	5,501	3,767
Prepaid seismic	1,004	667
Other Assets, net of amortization(1)	<u>\$ 68,932</u>	<u>\$ 65,831</u>

(1) Net of accumulated amortization as of December 31, 2009 and 2008 of \$10.4 million and \$6.4 million, respectively.

Derivative Financial Instruments — The Company utilizes derivative instruments 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 and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as cash flow hedges in accordance with accounting for derivatives and hedging under GAAP. Gains and losses resulting from these transactions, recorded at market value, are deferred and recorded in Accumulated Other Comprehensive Income as appropriate, until recognized as operating income in the Company's Consolidated Statements of Operations as the physical production hedged by the contracts is delivered. The Company presents the fair value of its derivatives on a net basis in accordance with GAAP.

Mariner is required to assess the effectiveness of all its derivative contracts at inception and at every quarter-end. If open contracts cease to qualify for hedge accounting, mark-to-market accounting is utilized and changes in the fair value of open contracts are recognized in the Consolidated Statements of Operations. Mark-to-market accounting may cause volatility in net income. Fair value is assessed, measured and estimated

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by obtaining forward commodity pricing, credit adjusted risk-free interest rates and estimated volatility factors. In addition, forward price curves and estimates of future volatility factors are used to assess and measure the effectiveness of the Company's open contracts at the end of each period. The fair values the Company reports in its Consolidated Financial Statements change as estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond its control.

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

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

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if correlation no longer exists, the gain or loss on the derivative is recognized in income.

Goodwill — The Company accounts for goodwill in accordance with GAAP which requires goodwill to be tested for impairment on an annual basis and between annual tests when events or circumstances indicate a potential impairment. In a purchase transaction, goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed. For the purpose of performing an impairment test, the Company has determined that it has one reporting unit. The goodwill impairment reviews consist of a two-step process. The first step is to determine the fair value of the Company's assets and compare it to the carrying value of the related net assets. Fair value is determined based on estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write-down is required. Step two is required if the fair value of the reporting unit is less than the carrying value of the net assets. In this step the implied fair value of the reporting unit is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written-down to its implied fair value.

The Company performs its goodwill test annually on November 30 and more often if circumstances require. At November 30, 2008, the Company had \$295.6 million in goodwill. In connection with its annual impairment test on November 30, 2008, Mariner performed a step one impairment analysis. As a result of weakened economic conditions and a decline in its stock price during the fourth quarter 2008, the carrying value of the Company exceeded the fair value of its net assets and a step two analysis was required to determine the impairment. Mariner's fair value estimates in step two were developed using a weighted average cost of capital ("WACC") of 12.0% and a control premium of 25.0%. A 1.0% increase and decrease of the WACC would have changed the fair value by (3.7%) and 4.0% respectively. The Company allocated the estimated fair value determined using these assumptions to the identifiable tangible and intangible assets and liabilities of the Company based on their respective values. This allocation indicated no residual value for goodwill and the Company recorded \$295.6 million of goodwill impairment in continuing operations as of December 31, 2008. As of December 31, 2009, Mariner had no remaining goodwill. As of December 31, 2008, Mariner had a net goodwill balance of zero consisting of \$295.6 million in accumulated goodwill impairment losses.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

Income Taxes — Mariner’s provision for taxes includes both state and federal taxes. The Company records its federal income taxes in accordance with accounting for income taxes under GAAP 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 basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered.

The Company also accounts for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact the Company’s financial position, results of operations and cash flows. The Company does not have uncertain tax positions outstanding and, as such, did not record a liability for the years ended December 31, 2009 and 2008.

Revenue Recognition — The Company recognizes oil and natural gas revenues when they are realized or realizable and earned. Revenues are considered realized or realizable and earned when persuasive evidence of an arrangement exists, delivery has occurred and title has transferred, the seller’s price to the buyer is fixed or determinable and collectability is reasonably assured.

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlement method to account for any imbalances. Imbalances occur when the Company sells more or less product than it is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and a receivable is accrued. Imbalances are reduced either by subsequent recoupment of over- and-under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are recorded 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 exists. At December 31, 2009 and 2008, the Company had gas imbalance payables of \$7.2 million and \$12.5 million, respectively, and gas imbalance receivables of \$7.0 million and \$17.8 million, respectively.

Major Customers — The table below presents the Company’s major customers. Management believes that the loss of any of these purchasers would not have a material impact on the Company’s financial condition, results of operations or cash flows.

Customer	Percentage of Total Revenues for Year Ended December 31,		
	2009	2008	2007
Williams Gas and affiliates	12%	5%	<1%
ChevronTexaco and affiliates	13%	16%	23%
Plains Marketing LP	11%	5%	7%
Shell	9%	10%	10%

Operating Costs — The Company classifies its operating costs as lease operating expense, severance and ad valorem taxes, transportation expense and general and administrative expense. Lease operating expense is

MARINER ENERGY, INC.**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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, workovers and the costs associated with production handling agreements for most of the Company's deepwater fields. Lease operating expense also includes 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 which are based on revenue.

Transportation expense includes variable costs associated with transportation of product to sales meters from the wellhead or field gathering point.

General and Administrative Expense — General and administrative expense includes employee compensation costs (including share-based 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.

Capitalized G&A — Under the full cost method of accounting, a portion of the Company's general and administrative expenses that are directly attributable to its acquisition, exploration and development activities are capitalized as part of its full cost pool. The Company capitalized general and administrative costs related to its acquisition, exploration and development activities of approximately \$21.2 million, \$19.8 million and \$14.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. Share-based compensation expense is classified with general and administrative expenses, except for amounts attributable to non-officer employees directly engaged in exploration, development and acquisition activities. See Note 5 "Stockholders' Equity" for further discussion on share-based compensation expense.

Overhead Recovery — The Company receives reimbursement for administrative and overhead expenses incurred on behalf of other working interest owners on properties it operates. These reimbursements totaling \$6.2 million, \$13.5 million and \$12.5 million for the years ended December 31, 2009, 2008 and 2007, respectively, were allocated as reductions to general and administrative expenses incurred. Generally, Mariner does not receive any reimbursements or fees in excess of the costs incurred; however, if it did, the Company would credit the excess to the full cost pool to be recognized through lower cost amortization as production occurs.

Concentration of Credit Risk — Mariner extends credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners' receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within the industry and may accordingly impact the Company's overall credit risk. However, the Company believes that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which it extends credit.

Use of Estimates — The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include (1) oil and natural gas reserves; (2) depreciation, depletion and amortization, including future abandonment costs; (3) assigning fair value and allocating purchase price in connection with business combinations, including goodwill; (4) income taxes; (5) accrued assets and liabilities; (6) share-based compensation; (7) asset retirement obligations and (8) valuation of derivative instruments. Although management believes these estimates are reasonable, actual results could differ from these estimates.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Net Income per Share — Basic earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding during the period. Fully diluted earnings per share assumes the conversion of all potentially dilutive securities and is calculated by dividing net income by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

Comprehensive Income — Comprehensive income includes net income and certain items recorded directly to stockholder's equity and classified as other comprehensive income. The table below summarizes comprehensive income and provides the components of the change in accumulated other comprehensive income for years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Net (Loss) Income	\$ (319,409)	\$ (388,525)	\$ 143,935
Other comprehensive (loss) income, net of tax:			
Change in unrealized mark-to-market (losses) gains arising during period, net of tax	(253,658)	165,675	(94,935)
Derivative contracts settled and reclassified, net of tax	149,529	(64,918)	29,262
Foreign currency translation adjustment	(7)	—	—
Change in accumulated other comprehensive (loss) income	(104,136)	100,757	(65,673)
Comprehensive (loss) income	(423,545)	(287,768)	78,262
Comprehensive income attributable to noncontrolling interest	—	188	1
Comprehensive (loss) income attributable to Mariner Energy, Inc.	\$ (423,545)	\$ (287,956)	\$ 78,261

Recent Accounting Pronouncements — In February 2010, the Financial Accounting Standards Board (FASB) issued authoritative guidance which requires additional information to be disclosed principally in respect of Level 3 fair value measurements and transfers to and from Level 1 and Level 2 measurements. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 fair value measurements. The guidance is generally effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. The Company is currently evaluating the potential impact of adoption.

In January 2010, FASB issued Accounting Standards Update (ASU) 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the new SEC rules. The ASU amends existing standards to align the reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. The Company adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate.

In June 2009, the FASB issued authoritative guidance on the hierarchy of GAAP which established only two levels of GAAP, authoritative and non-authoritative. The FASB Accounting Standards Codification ("ASC" or the "Codification") will become the source of authoritative, nongovernmental GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants upon adoption. All other non-grandfathered, non-SEC accounting literature not included in the Codification will

MARINER ENERGY, INC.

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become non-authoritative. The Codification is effective for financial statements for interim or annual reporting periods ending after September 15, 2009. The Company began using the new guidelines prescribed by the Codification when referring to GAAP in respect of the third quarter ending September 30, 2009. As the Codification was not intended to change or alter existing GAAP, it did not have any impact on the Company's consolidated financial position, cash flows or results of operations.

In May 2009, the FASB issued authoritative guidance which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued and sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The guidance is effective for periods beginning after June 15, 2009. The adoption did not have a material impact on the Company's financial position, cash flows or results of operations.

In April 2009, the FASB amended existing authoritative guidance to provide guidelines for making fair value measurements more consistent with other authoritative guidance, enhance consistency in financial reporting by increasing the frequency of fair value disclosures and create greater clarity and consistency in accounting for and presenting impairment losses on securities. This guidance is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Company adopted the provisions for the period ending March 31, 2009. The adoption did not have a material impact on the Company's financial position, cash flows or results of operations.

On December 31, 2008, the SEC issued the Final Rule, which adopts revisions to the SEC's oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and changes in technology. Revised requirements in the Final Rule include, but are not limited to:

- Oil and gas reserves must be reported using the average price over the prior 12-month period, rather than year-end prices;
- Companies are allowed to report, on an optional basis, probable and possible reserves;
- Non-traditional reserves, such as oil and gas extracted from coal and shales, are included in the definition of "oil and gas producing activities";
- Companies are permitted to use new technologies to determine proved reserves, as long as those technologies have been demonstrated empirically to lead to reliable conclusions with respect to reserve volumes;
- Companies are required to disclose, in narrative form, additional details on their proved undeveloped reserves (PUDs), including the total quantity of PUDs at year end, any material changes to PUDs that occurred during the year, investments and progress made to convert PUDs to developed oil and gas reserves and an explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs;
- Companies are required to report the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates.

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The adoption of this rule did have a material impact on the Company's results of operations and financial position as the average price used over the 12-month period to calculate the full cost ceiling test impairment and the Company's proved reserves was lower than the year-end spot prices that would have been used under the previous rule for oil and natural gas. The Company recorded a full cost ceiling test impairment of \$49.6 million in the fourth quarter 2009 primarily as a result of using a 12-month average price. The adoption of this rule did not have a material impact on the Company's cash flows.

In December 2007, the FASB issued ASC 805 which establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. The guidance also establishes disclosure requirements which will enable users to evaluate the nature and financial effects of the business combination. The guidance was effective for fiscal years beginning after December 15, 2008; the Company adopted it beginning January 1, 2009. The adoption did impact the Company's accounting for business combinations in respect of the acquisition of the reorganized subsidiaries of Edge Petroleum Corporation ("Edge") on December 31, 2009. See Note 2 "Acquisitions" for further details.

In December 2007, the FASB issued authoritative guidance which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The guidance also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. The guidance was effective for fiscal years beginning after December 15, 2008; the Company adopted it beginning January 1, 2009. The adoption did not have a material impact on the Company's results of operations, financial position or cash flows. However, it did impact the presentation and disclosure of noncontrolling (minority) interests in its consolidated financial statements.

In September 2006, the FASB issued authoritative guidance for fair value measurements, which defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. The guidance was effective for all recurring measures of financial assets and financial liabilities (e.g. derivatives and investment securities) for fiscal years beginning after November 15, 2007. The Company adopted the provisions for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB amended the authoritative guidance, which granted a one-year deferral of the effective date as it applied to nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value on a nonrecurring basis. Beginning January 1, 2009, Mariner applied the provisions to non-financial assets and liabilities. The adoption did not have a material impact on the Company's results of operations, financial position and cash flow.

Note 2. Acquisitions

Onshore Acquisition — On December 31, 2009, Mariner acquired the reorganized subsidiaries and operations of Edge. The assets acquired consist primarily of (i) estimated proved reserves, (ii) undeveloped oil and gas property, primarily in Texas and New Mexico, (iii) exploration assets in the form of seismic data, and (iv) certain tax attributes of the acquired subsidiaries. The effective date of the acquisition was June 30, 2009 and the purchase price was \$260.0 million, less adjustments which resulted in a net purchase price as of December 31, 2009 of approximately \$213.6 million, subject to final adjustments. Mariner financed the net purchase price by borrowing under its secured revolving credit facility.

The acquisition was accounted for under the purchase method of accounting in accordance with ASC 805 relating to "Business Combinations". The purchase method requires the assets and liabilities acquired to be recorded at their fair values at the date of acquisition. No results of operations were recorded in the

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Consolidated Statement of Operations for the year-ended December 31, 2009. Transaction costs related to the acquisition were approximately \$0.6 million, which were expensed as incurred and recorded as “General and administrative expenses” in the Consolidated Statement of Operations for the year ended December 31, 2009. The preliminary estimate of fair values as of December 31, 2009 is as follows (in thousands):

Proved oil and gas properties	\$ 206,291
Unproved properties	36,695
Abandonment liability	(5,455)
	<u>\$ 237,531</u>

In accordance with accounting for taxes in a business combinations under ASC 740, the acquired tax attributes were recorded based on the expected undiscounted amounts to be realized in future periods using the enacted tax rates. The preliminary estimate of associated deferred taxes recorded as of December 31, 2009 is as follows (in thousands):

Net operating losses	\$ 61,182
Built-in losses from carryover tax basis in the properties	<u>22,097</u>
	<u>\$ 83,279</u>

The following describes the procedures used to measure the amounts recognized at the acquisition date for the assets acquired and liabilities assumed in the acquisition. The Company applied a tax rate of 35%, which approximates the effective tax rate for the year ended December 31, 2009. Mariner also applied a weighted average cost of capital (“WACC”) that measures the returns required by both debt and equity investors, weighted by their respective contributions of capital. The WACC used to measure the acquired assets was 14%.

- *Proved properties* — The Company valued proved properties using a discounted cash flow method for the proved developed and undeveloped reserves acquired. Market strip prices were used for barrels of oil and MMBtus of natural gas as of December 31, 2009 for the first five years of the reserve life and then held constant for the remaining life of the reserves. These prices were adjusted for the Company’s price differentials. Operating costs associated with those reserves were established based on the Company’s current estimate of operating costs and fixed throughout the life of the reserves, including estimates of abandonment costs. Production and ad valorem taxes, as a percentage of revenue, were applied to the revenue value. Management estimated an additional risk associated with PUD volumes and risked those volumes at 80%.
- *Unproved properties* — This amount consists of leasehold acreage and unproved properties acquired, and proprietary seismic data which may be sold to third parties on a licensed basis. The Company valued the leasehold acreage using a market transaction approach of reviewing transactions in proximate locations as an indication of fair value from a market participant perspective. The market values for leasehold acreage were obtained for the respective areas of properties acquired and a per acre valuation was applied. The Company valued this seismic data using a replacement cost approach adjusted for technological obsolescence.
- *Abandonment Liability* — The Company used a present value technique to measure the fair value of the associated abandonment liability. The assumptions applied to calculate this amount included the same

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credit-adjusted risk-free interest rate and inflation rate used to account for other abandonment liabilities recorded, the associated estimated settlement date and current cost to settle the liability.

- *Deferred Tax Assets* — The Company measured the deferred tax assets based on the expected undiscounted amounts to be realized in future periods using the enacted tax rates. The tax attributes of the subsidiaries acquired consist of federal net operating loss carryforwards estimated at \$174.8 million and built-in losses estimated at \$87.1 million associated with the tax basis in the properties. The transaction to acquire the reorganized Edge subsidiaries was structured as a stock purchase to preserve the carryover tax attributes of the Edge subsidiaries.

After applying the respective methods discussed above to record the preliminary estimate of fair value associated with the assets and liabilities acquired as well as recording the tax attributes on an undiscounted basis in accordance with GAAP, the Company recorded a gain on the acquisition of approximately \$107.3 million included in “Gain on acquisition” in the Consolidated Statement of Operations for the year ended December 31, 2009. The excess of the net assets acquired over the estimated purchase price consisted of approximately \$24.0 million of property and approximately \$83.3 million in deferred tax assets. The deferred tax assets are comprised of approximately \$61.2 million in net operating loss carryforwards and \$22.1 million in built-in losses from carryover tax basis in the properties.

A gain on acquisition, or a bargain purchase, can happen in a business combination that, among certain other situations, is a forced sale in which the seller is acting under compulsion. Edge filed for federal bankruptcy protection in October 2009. In December 2009, Mariner was the winning bidder in the bankruptcy auction for Edge’s subsidiaries. In addition, a buyer is required to recognize in income from continuing operations changes in the amount of the recognizable deferred tax benefits resulting from a business combination when circumstances allow. The Company structured the purchase of Edge’s reorganized subsidiaries as a stock acquisition to obtain the associated tax attributes that Mariner expects to benefit from in future periods. Those attributes were recorded as deferred tax assets and contributed to the gain recognized on acquisition.

Pro Forma Financial Information: The unaudited pro forma information set forth below gives effect to the acquisition of the reorganized Edge subsidiaries as if it had been consummated as of the beginning of the applicable period. The unaudited pro forma information has been derived from the historical Consolidated Financial Statements of the Company and of Edge. The unaudited pro forma information is for illustrative purposes only. The financial results may have been different had each of the acquired Edge subsidiaries been an independent company and had the companies always been combined. You should not rely on the unaudited pro forma financial information as being indicative of the historical results that would have been achieved had the acquisition occurred in the past or the future financial results that the Company will achieve after the acquisition.

	For the Year Ended December 31,	
	2009	2008
	(Unaudited)	
	(In thousands, except per share amounts)	
Pro Forma:		
Revenue	\$ 1,005,252	\$ 1,461,783
Net (loss) income available to common stockholders	\$ (437,622)	\$ (660,322)
Basic (loss) earnings per share	\$ (4.58)	\$ (7.55)
Diluted (loss) earnings per share	\$ (4.58)	\$ (7.55)

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Gulf of Mexico Shelf Acquisition — On January 31, 2008, Mariner acquired 100% of the equity in a subsidiary of Hydro Gulf of Mexico, Inc. pursuant to a Membership Interest Purchase Agreement executed on December 23, 2007. The acquired subsidiary, now known as Mariner Gulf of Mexico LLC (“MGOM”), was an indirect subsidiary of StatoilHydro ASA and owns substantially all of its former Gulf of Mexico shelf operations. Mariner paid \$228.8 million for the acquisition of MGOM.

Permian Basin Acquisitions — On February 29, 2008 and December 1, 2008, Mariner acquired additional working interests in certain of its existing properties in the Spraberry field in the Permian Basin. Mariner operates substantially all of the assets. The purchase prices were \$23.5 million for the February 2008 acquisition and \$19.4 million for the December 2008 acquisition.

Bass Lite — On December 19, 2008, Mariner acquired additional working interests in its existing property, Atwater Valley Block 426 (Bass Lite), for approximately \$30.6 million, increasing its working interest by 11.6% to 53.8%. Mariner internally estimated proved reserves attributable to the acquisition of approximately 17.6 Bcfe (100% natural gas).

Note 3. Long-Term Debt

As of December 31, 2009 and December 31, 2008 the Company’s long-term debt was as follows:

	<u>December 31,</u> <u>2009</u>	<u>December 31,</u> <u>2008</u>
(In thousands)		
Bank credit facility	\$ 305,000	\$ 570,000
11 ³ / ₄ % Senior Notes, due June 30, 2016, net of discount	291,725	—
8% Senior Notes, due May 15, 2017	300,000	300,000
7 ¹ / ₂ % Senior Notes, due April 15, 2013, net of discount	298,125	300,000
Total long-term debt	<u>\$ 1,194,850</u>	<u>\$ 1,170,000</u>

Bank Credit Facility — The Company has a secured revolving credit facility with a group of banks pursuant to an amended and restated credit agreement dated March 2, 2006, as further amended. The credit facility matures January 31, 2012 and is subject to a borrowing base which is redetermined periodically. As of December 31, 2009, maximum credit availability under the facility was \$1.0 billion, including up to \$50.0 million in letters of credit, subject to a borrowing base of \$800.0 million scheduled to be redetermined in February 2010. The redetermination was pending on February 28, 2010, and Mariner anticipates that it will occur in March 2010.

The lenders redetermine the borrowing base periodically based upon their evaluation of the Company’s oil and gas reserves and other factors. Any increase in the borrowing base requires the consent of all lenders. The outstanding principal balance of loans under the credit facility may not exceed the borrowing base. If the borrowing base falls below the sum of the amount borrowed and uncollateralized letter of credit exposure, then to the extent of the deficit, the Company must prepay borrowings and cash collateralize letter of credit exposure, pledge additional unencumbered collateral, repay borrowings and cash collateralize letters of credit on an installment basis, or effect some combination of these actions.

The Company has used borrowings under the facility to facilitate acquisitions, and has used and may use borrowings under the facility for general corporate purposes. On June 10, 2009, the Company used aggregate proceeds from concurrent offerings of its 11³/₄% senior notes due 2016 and common stock, before deducting estimated offering expenses but after deducting underwriters’ discounts and commissions, of approximately \$446.2 million to repay debt under its bank credit facility. These offerings are discussed further below in this

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Note 3 and in Note 4 “Stockholders’ Equity.” The Company funded its December 2009 acquisition of the reorganized Edge subsidiaries by borrowing approximately \$213.6 million under the credit facility.

As of December 31, 2009 and 2008, advances outstanding under the credit facility were \$305.0 million and \$570.0 million, respectively. In addition, as of December 31, 2009 four letters of credit were outstanding totaling \$4.7 million, of which \$4.2 million is required for plugging and abandonment obligations at certain of the Company’s offshore fields. As of December 31, 2009, after accounting for the \$4.7 million of letters of credit, the Company had \$490.3 million available to borrow under the credit facility.

Borrowings under the bank credit facility bear interest at either a LIBOR-based rate or a prime-based rate, at the Company’s option, plus a specified margin. At December 31, 2009, when borrowings at both LIBOR and prime-based rates were outstanding, the blended interest rate was 3.40% on all amounts borrowed. At December 31, 2008, the interest rate was 3.31%. During the year ended December 31, 2009, the commitment fee on unused capacity was 0.250% to 0.375% per annum through March 23, 2009 and 0.5% per annum thereafter. Commitment fees are included in “Accrued interest” in the Consolidated Balance Sheets accompanying these Notes.

The credit facility subjects the Company to various restrictive covenants and contains other usual and customary terms and conditions, including limits on additional debt, cash dividends and other restricted payments, liens, investments, asset dispositions, mergers and speculative hedging. Financial covenants under the credit facility require the Company to:

- maintain a ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities of not less than 1.0 to 1.0; and
- maintain a ratio of total debt to EBITDA (as defined in the credit agreement) of not more than 2.5 to 1.0.

The Company was in compliance with these covenants as of December 31, 2009 when the ratio of consolidated current assets plus the unused borrowing base to consolidated current liabilities was 2.38 to 1.0 and the ratio of total debt to EBITDA was 1.99 to 1.0.

The Company’s payment and performance of its obligations under the credit facility (including any obligations under commodity and interest rate hedges entered into with facility lenders) are secured by liens upon substantially all of the assets of the Company and its subsidiaries, except its Canadian subsidiary, and guaranteed by its subsidiaries, other than Mariner Energy Resources, Inc. which is a co-borrower, and its Canadian subsidiary.

Senior Notes — On June 10, 2009, the Company sold and issued \$300.0 million aggregate principal amount of its 11³/₄% Senior Notes due 2016 (the “11³/₄% Notes”). The 11³/₄% Notes were sold at 97.093% of principal amount, for an initial yield to maturity of 12.375%, in an underwritten offering registered under the Securities Act of 1933, as amended (the “1933 Act”). Net offering proceeds, after deducting underwriters’ discounts and estimated offering expenses but before giving effect to the underwriters’ reimbursement of up to \$0.5 million for offering expenses, were approximately \$284.8 million. The Company used net offering proceeds (before deducting estimated offering expenses) to repay debt under its bank credit facility. The 11³/₄% Notes were issued under an Indenture among the Company, the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (the “Base Indenture”), as amended and supplemented by the First Supplemental Indenture thereto among the same parties, each dated as of June 10, 2009. Pursuant to the Base Indenture, the Company may issue multiple series of debt securities from time to time.

On April 30, 2007, the Company sold and issued \$300.0 million aggregate principal amount of its 8% Senior Notes due 2017 (the “8% Notes”). The 8% Notes were sold at par in an underwritten offering registered under the 1933 Act. Net offering proceeds, after deducting underwriters’ discounts and offering

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expenses, were approximately \$293.4 million. The Company used the net offering proceeds to repay debt under its bank credit facility.

On April 24, 2006, the Company sold and issued to eligible purchasers \$300.0 million aggregate principal amount of its 7¹/₂% Senior Notes due 2013 (the “7¹/₂% Notes” and together with the 11³/₄% Notes and the 8% Notes, the “Notes”) pursuant to Rule 144A under the 1933 Act. The 7¹/₂% Notes were priced to yield 7.75% to maturity. On November 9, 2006, the Company replaced the original Notes issued in the private placement with new Notes with identical terms and tenor through an exchange offer registered under the 1933 Act.

The Notes are governed by indentures that are substantially identical for each series. The Notes are senior unsecured obligations of the Company, rank senior in right of payment to any future subordinated indebtedness, rank equally in right of payment with each other and with the Company’s existing and future senior unsecured indebtedness, and are effectively subordinated in right of payment to the Company’s senior secured indebtedness, including its obligations under its bank credit facility, to the extent of the collateral securing such indebtedness, and to all existing and future indebtedness and other liabilities of any non-guarantor subsidiaries.

The Notes are jointly and severally guaranteed on a senior unsecured basis by the Company’s existing and future domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. Each subsidiary guarantee ranks senior in right of payment to any future subordinated indebtedness of the guarantor subsidiary, ranks equally in right of payment to all existing and future senior unsecured indebtedness of the guarantor subsidiary and effectively subordinate to all existing and future secured indebtedness of the guarantor subsidiary, including its guarantees of indebtedness under the Company’s bank credit facility, to the extent of the collateral securing such indebtedness.

The 11³/₄% Notes mature on June 30, 2016 with interest payable on June 30 and December 30 of each year beginning December 30, 2009. The 8% Notes mature on May 15, 2017 with interest payable on May 15 and November 15 of each year. The 7¹/₂% Notes mature on April 15, 2013 with interest payable on April 15 and October 15 of each year. There is no sinking fund for the Notes.

The Company may redeem the 11³/₄% Notes at any time before June 30, 2013, the 8% Notes at any time before May 15, 2012 and the 7¹/₂% Notes at any time before April 15, 2010, in each case at a price equal to the principal amount redeemed plus a make-whole premium, using a discount rate of the Treasury rate plus 0.50% and accrued but unpaid interest. Beginning on the dates indicated below, the Company may redeem the Notes from time to time, in whole or in part, at the prices set forth below (expressed as percentages of the principal amount redeemed) plus accrued but unpaid interest:

<u>11³/₄% Notes</u>	<u>8% Notes</u>	<u>7¹/₂% Notes</u>
June 30, 2013 at 105.875%	May 15, 2012 at 104.000%	April 15, 2010 at 103.750%
June 30, 2014 at 102.938%	May 15, 2013 at 102.667%	April 15, 2011 at 101.875%
June 30, 2015 and after at 100.000%	May 15, 2014 at 101.333%	April 15, 2012 and after at 100.000%
	May 15, 2015 and after at 100.000%	

In addition, before June 30, 2012, the Company may redeem up to 35% of the 11³/₄% Notes with the proceeds of equity offerings at a price equal to 111.750% of the principal amount of the 11³/₄% Notes redeemed plus accrued but unpaid interest. Before May 15, 2010, the Company may redeem up to 35% of the 8% Notes with the proceeds of equity offerings at a price equal to 108% of the principal amount of the 8% Notes redeemed plus accrued but unpaid interest.

If a change of control triggering event (as defined in each of the indentures governing the Notes) occurs, subject to certain exceptions, the Company must give holders of the Notes the opportunity to sell to the

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Company their Notes, in whole or in part, at a purchase price equal to 101% of the principal amount, plus accrued and unpaid interest and liquidated damages to the date of purchase.

The Company and its restricted subsidiaries are subject to certain negative covenants under each of the indentures governing the Notes. The indentures limit the ability of the Company and each of its restricted subsidiaries to, among other things:

- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from its subsidiaries to itself;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates;
- pay dividends or make other distributions on capital stock or subordinated indebtedness; and
- create unrestricted subsidiaries.

Costs associated with the 11^{3/4}% Notes offering were approximately \$5.9 million, excluding discounts of \$8.7 million. Costs associated with the 8% Notes offering included aggregate underwriting discounts of approximately \$5.3 million and offering expenses of approximately \$1.3 million. Costs associated with the 7^{1/2}% Notes offering were approximately \$8.5 million, excluding discounts of \$3.8 million.

Capitalized Interest — For the period ended December 31, 2009 and 2008, capitalized interest totaled \$14.7 million and \$9.7 million, respectively.

Cash Interest Expense — For the years ended December 31, 2009, 2008 and 2007 interest payments were \$83.6 million, \$62.2 million and \$49.1 million, respectively.

Bank Debt Issuance Costs — The Company capitalizes certain direct costs associated with the issuance of long-term debt. For the years ended December 31, 2009 and 2008 the Company capitalized \$6.6 million and \$2.3 million in debt issuance costs, included in “Other Assets, net of amortization” on the Consolidated Balance Sheet.

Note 4. Stockholders’ Equity

Common Stock Offering — On June 10, 2009, the Company sold and issued 11.5 million shares of its common stock, par value \$.0001 per share, at a public offering price of \$14.50 per share in an underwritten offering registered under the 1933 Act. The total sold includes 1.5 million shares issued upon full exercise of the underwriters’ overallotment option. Net offering proceeds, after deducting underwriters’ discounts and estimated offering expenses but before giving effect to the underwriters’ reimbursement of up to \$0.5 million for offering expenses, were approximately \$159.2 million. The Company used net offering proceeds (before deducting estimated offering expenses of approximately \$0.5 million) to repay debt under its bank credit facility.

Earnings Per Share — Basic earnings per share does not include dilution and is computed by dividing net income or loss attributed to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted earnings per share reflect the potential dilution that could occur if security interests were exercised or converted into common stock.

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The following table sets forth the computation of basic and diluted earnings per share for the years ended December 31, 2009, 2008 and 2007.

	2009			2008			2007		
	Net Income Attributed to Common Stock	Weighted- Average Shares	Per- Share Income/ (Loss)	Net Income Attributed to Common Stock	Weighted- Average Shares	Per- Share Income/ (Loss)	Net Income Attributed to Common Stock	Weighted- Average Shares	Per- Share Income/ (Loss)
	(In thousands, except per share data)								
Basic net (loss) income attributable to Mariner Energy, Inc. per share	\$ (319,409)	95,607	\$ (3.34)	\$ (388,713)	87,491	\$ (4.44)	\$ 143,934	85,645	\$ 1.68
Effect of dilutive securities:	—	—	—	—	—	—	—	481	(0.01)
Diluted net (loss) income attributable to Mariner Energy, Inc. per share	\$ (319,409)	95,607	\$ (3.34)	\$ (388,713)	87,491	\$ (4.44)	\$ 143,934	86,126	\$ 1.67

Shares issuable upon exercise of options to purchase common stock and unvested shares of restricted stock that would have been anti-dilutive are excluded from the computation of diluted earnings per share. Due to Mariner’s net loss for the year ended December 31, 2009, approximately 623,000 shares issuable upon exercise of stock options and 2,044,000 unvested shares of restricted stock were excluded from the computation of diluted earnings per share because the effect was anti-dilutive. Due to the Company’s net loss for the year ended December 31, 2008, approximately 236,000 shares issuable upon exercise of stock options and 1,088,000 unvested shares of restricted stock were excluded from the computation of diluted earnings per share because the effect was anti-dilutive. Approximately 513,000 shares issuable upon exercise of stock options were excluded from the computation for year ended December 31, 2007 because the effect was anti-dilutive.

Authorized Stock — The Company’s certificate of incorporation, as amended, authorizes 200,000,000 shares of stock, of which 180,000,000 shares are common stock and 20,000,000 shares are preferred stock. In connection with the rights plan discussed below, the Company filed with the Delaware Secretary of State on October 13, 2008 a certificate of designations of Series A Junior Participating Preferred Stock which consists of 180,000 shares. As of December 31, 2009, no preferred stock had been issued.

Rights Plan — On October 12, 2008, Mariner’s board of directors adopted a rights plan pursuant to which it declared and paid a dividend of one right (“Right”) for each outstanding share of the Company’s common stock to holders of record at the close of business on October 23, 2008. The rights plan is intended to safeguard the interests of Mariner’s stockholders by serving as a general deterrent to potentially unfair or coercive takeover practices, especially those exploiting market instability. The Rights generally would become exercisable if an acquiring party accumulates 10% or more of Mariner’s common stock and entitle holders of Rights to purchase stock of either Mariner or an acquiring entity at half of market value. The Rights are governed by a Rights Agreement, dated as of October 12, 2008, between Mariner and Continental Stock Transfer & Trust Company, as Rights Agent (the “Rights Agreement”).

Each Right entitles the registered holder to purchase from Mariner under certain circumstances a unit consisting of one one-thousandth of a share of its Series A Junior Participating Preferred Stock, par value \$0.0001 per share, at a purchase price of \$75.00 per fractional share, subject to adjustment. The Rights are not exercisable (and are transferable only with Mariner’s common stock) until a “Distribution Date” occurs (or they are earlier redeemed or expire), which generally occurs on the 10th day following a public announcement that a person or group of affiliated or associated persons (an “Acquiring Person”) has acquired beneficial ownership of 10% or more of Mariner’s outstanding common stock or after the commencement or

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announcement of a tender offer or exchange offer which would result in any such person or group of persons acquiring such beneficial ownership. Until a Right is exercised, the holder thereof, as such, has no rights as a stockholder of the Company.

If a person becomes an Acquiring Person, holders of Rights will be entitled to purchase shares of Mariner's common stock for one-half its current market price, as defined in the Rights Agreement. This is referred to as a "flip-in event" under the Rights Agreement. After any flip-in event, all Rights that are beneficially owned by an Acquiring Person, or by certain related parties, will be null and void. Mariner's board of directors has the power to decide that a particular tender or exchange offer for all outstanding shares of Mariner's common stock is fair to, and otherwise in the best interests of, its stockholders. If the Board makes this determination, the purchase of shares under the offer will not be a flip-in event.

If, after there is an Acquiring Person, Mariner is acquired in a merger or other business combination transaction or 50% or more of its assets, earning power or cash flow are sold or transferred, each holder of a Right will have the right to purchase shares of the acquiring company's common stock at a price of one-half the current market price of that stock. This is referred to as a "flip-over event" under the Rights Agreement. An Acquiring Person will not be entitled to exercise its Rights, which will have become void.

The Rights expire on October 12, 2018 unless extended or earlier redeemed or exchanged by the Company. Mariner generally is entitled to redeem the Rights at \$.001 per Right at any time until the tenth day after the Rights become exercisable. At any time after a flip-in event and before either a person becomes the beneficial owner of 50% or more of Mariner's outstanding common stock or a flip-over event, the Company's board of directors may decide to exchange the Rights for shares of Mariner's common stock on a one-for-one basis. Rights owned by an Acquiring Person, which will have become void, will not be exchanged.

Note 5. Share-Based Compensation

The Company accounts for its share-based compensation in accordance with fair value recognition provisions of accounting for stock compensation under GAAP. Under those fair value recognition provisions, share-based compensation is measured at the grant date based on the calculated fair value of the award and is recognized as an expense over the requisite employee service period, which generally equals the vesting period of the grant. The Company determines share-based compensation expense for restricted stock and option grants equal to their fair value at the date of grant. The fair value then is amortized to share-based compensation expense over the applicable vesting period.

Share-based compensation, including restricted stock and options under each of the Company's plans, for the years ended December 31, 2009, 2008 and 2007 was:

	Year Ended December 31		
	2009	2008	2007
	(In thousands)		
Share-based compensation included in:			
General and administrative expense	\$ 25,434	\$ 21,017	\$ 10,890
Oil and natural gas properties under full cost method	3,663	2,956	—
Total share-based compensation	<u>\$ 29,097</u>	<u>\$ 23,973</u>	<u>\$ 10,890</u>

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For the Years Ended December 31, 2009, 2008 and 2007

Share-based compensation charged to earnings for the years ended December 31, 2009, 2008 and 2007 was:

	Year Ended December 31		
	2009	2008	2007
	(In thousands)		
Charged to earnings	\$ 25,434	\$ 21,017	\$ 10,890
Tax benefit	(8,775)	(7,188)	(3,801)
	<u>\$ 16,659</u>	<u>\$ 13,829</u>	<u>\$ 7,089</u>

Applicable Plans — On May 11, 2009, the Company’s stockholders approved the Mariner Energy, Inc. Third Amended and Restated Stock Incentive Plan (the “Stock Incentive Plan”). Restricted common stock and non-qualified stock options are outstanding under the Stock Incentive Plan pursuant to grants made since 2005. Non-qualified options to purchase the Company’s common stock granted to certain employees in connection with a March 2006 merger transaction also are outstanding but are not governed by the Stock Incentive Plan (“Rollover Options”).

The Company’s directors, employees and consultants are eligible to participate in the Stock Incentive Plan. Awards to participants may be made in the form of incentive stock options, non-qualified stock options or restricted stock. Effective May 11, 2009, the Stock Incentive Plan increased to 12,500,000 from 6,500,000 the maximum number of shares of the Company’s common stock that can be issued to participants, and increased the number of shares that can be issued to any one employee to 5,700,000 from 2,850,000. Subject to the terms of the Stock Incentive Plan, the participants to whom awards are granted, the type or types of awards granted, the number of shares covered by each award, and the purchase price, conditions and other terms of each award are determined by the Company’s board of directors or a committee thereof appointed by the board to administer the Plan (the “committee”).

Unless sooner terminated, no award may be granted under the Stock Incentive Plan after October 12, 2015. The Company’s board of directors or the committee may amend, alter, suspend, discontinue, or terminate (collectively, “change”) the Stock Incentive Plan without the consent of any stockholder, participant, other holder or beneficiary of an award, or other person, except that:

- without the approval of the Company’s stockholders, no change can be made that would
 - (i) increase the total number of shares that may be issued under the Stock Incentive Plan, except as provided in the Stock Incentive Plan with respect to stock dividends or splits, or with respect to mergers, recapitalizations, reorganizations, spin-offs or other unusual transactions or events,
 - (ii) permit the exercise price of any outstanding option that is “underwater” to be reduced or for an “underwater” option to be cancelled and replaced with a new award,
 - (iii) include participants other than employees, non-employee directors and consultants, or
 - (iv) materially increase benefits accrued to participants under the Stock Incentive Plan; and
- no change can materially adversely affect the rights of a participant under an award without the participant’s written consent.

In addition, the Stock Incentive Plan may not be amended or terminated in any manner that would cause the Plan or any amounts or benefits payable under the Stock Incentive Plan to fail to comply with Section 409A of the Internal Revenue Code of 1986, as amended, to the extent applicable.

As of December 31, 2009, 7,070,824 shares remained available for future issuance to participants under the Stock Incentive Plan. During the year ended December 31, 2009, 713,694 shares of restricted stock vested

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under the Stock Incentive Plan, resulting in withholding tax obligations. Plan participants can elect to have Mariner withhold and cancel shares of restricted stock to satisfy the associated tax withholding obligations. In such event, Mariner would be required to pay any tax withholding obligation in cash. As a result of such participant elections, the Company withheld an aggregate 216,469 shares in the year ended December 31, 2009 that otherwise would have remained outstanding upon vesting of the restricted stock. The shares withheld became treasury shares that were retired and restored to the status of authorized and unissued shares of common stock, and the Company's capital was reduced by an amount equal to the \$.0001 par value of the retired shares. Mariner paid in cash the associated withholding taxes of approximately \$2.7 million for the year ended December 31, 2009.

Restricted Stock Grants

Restricted stock granted under the Stock Incentive Plan is issued on the grant date, but is restricted as to transferability. Restricted stock grants generally vest over periods ranging from three to four years, except for grants made under the Stock Incentive Plan's Long-Term Performance-Based Restricted Stock Program discussed below. Compensation cost for all awards of restricted stock under the Stock Incentive Plan is based on the closing market price of Mariner's common stock on the date of grant. Share-based compensation expense is based on the awards ultimately expected to vest, and has been reduced for estimated forfeitures.

The following table summarizes the status under GAAP of the Company's restricted stock, including long-term performance based restricted stock, at December 31, 2009 and the changes during the year then ended:

	<u>Equity Instruments (in thousands)</u>	<u>Weighted Average Fair Value</u>	<u>Aggregate Intrinsic Value (in thousands)</u>	<u>Weighted Average Remaining Contractual Life (Years)</u>
Unvested at January 1, 2009	2,697,926	\$ 28.22	\$ 76,123	
Granted	1,742,007	11.25	19,594	
Vested	(713,694)	21.33	(15,221)	
Forfeited	(65,974)	26.70	(1,762)	
Unvested at December 31, 2009	<u>3,660,265</u>	<u>\$ 21.51</u>	<u>\$ 78,734</u>	6.07

The weighted average grant date fair value of restricted stock granted, including long-term performance based restricted stock, during the years ended December 31, 2008 and 2007 was \$32.28 per share and \$21.98 per share, respectively.

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The following table shows a summary of the activity for unvested restricted stock awards under the Stock Incentive Plan during the years 2009, 2008 and 2007:

	Restricted Shares under the Stock Incentive Plan		
	2009	2008	2007
Total unvested shares at beginning of period: January 1	2,697,926	1,484,552	875,380
Shares granted(1)	1,742,007	1,734,070	906,104
Shares vested	(713,694)	(490,881)	(251,332)
Shares forfeited(1)	(65,974)	(29,815)	(45,600)
Total unvested shares at end of period: December 31	3,660,265	2,697,926	1,484,552
Total shares vested at end of period: December 31	1,460,407	746,713	255,832
Available for future grant as options or restricted stock	7,070,824	2,530,388	4,072,801
Average fair value of shares granted during the period	\$ 11.32	\$ 30.27	\$ 21.73

(1) 2009 activity includes 4,741 shares granted and forfeited under the Stock Incentive Plan's 2008 Long-Term Performance-Based Restricted Stock Program discussed below.

The total fair value of restricted shares that became vested during 2009, 2008 and 2007 was \$8.7 million, \$14.5 million and \$5.5 million, respectively.

At December 31, 2009, unrecognized compensation expense under the Stock Incentive Plan for the unvested portion of restricted stock grants was \$46.0 million. These costs are expected to be recognized over a weighted-average period of approximately four years.

Long-Term Performance-Based Restricted Stock Program — In June 2008, Mariner's board of directors adopted a Long-Term Performance-Based Restricted Stock Program (the "Program") under the Stock Incentive Plan. Shares of restricted common stock subject to the Program were granted during the years ended December 31, 2008 and 2009. Vesting of these shares is contingent, begins upon satisfaction of specified thresholds of \$38.00 and \$46.00 for the market price per share of Mariner's common stock, and continues in installments over five to seven years thereafter, assuming, in most instances, continued employment by Mariner. The fair value of restricted stock grants made under the Program is estimated using a Monte Carlo simulation. Stock-based compensation expense related to these restricted stock grants totaled \$11.0 million and \$6.4 million for the 12 months ended December 31, 2009 and 2008, respectively.

Weighted average fair values and valuation assumptions used to value Program grants for the year ended December 31, 2009 are as follows:

	Year Ended December 31, 2009
Weighted average fair value of grants	\$ 33.73
Expected volatility	42.29%
Risk-free interest rate	4.57%
Dividend yield	0.00%
Expected life	10 years

Expected volatility is calculated based on the average historical stock price volatility of Mariner and a peer group as of December 31, 2009. The peer group consisted of the following seven independent oil and gas exploration and production companies: ATP Oil & Gas Corporation, Callon Petroleum Co., Energy Partners, Ltd., McMoRan Exploration Co., Plains Exploration & Production Company, Stone Energy Corporation, and

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W&T Offshore, Inc. The risk-free interest rate is determined at the grant date and is based on 10-year, zero-coupon government bonds with maturity equal to the contractual term of the awards, converted to a continuously compounded rate. The expected life is based upon the contractual terms of the restricted stock grants under the Program.

Stock Option Grants

As of December 31, 2009, the only option grants under the Stock Incentive Plan were made in 2005 exercisable to purchase 809,000 shares of common stock. Rollover Options were granted in 2006 to purchase 156,626 shares of common stock. All outstanding options had fully vested by December 31, 2008. Compensation cost for option awards is determined using a Black-Scholes valuation model. Share-based compensation expense is based on the awards ultimately expected to vest and has been reduced for estimated forfeitures.

The following table presents a summary of stock option activity, inclusive of the stock options under the Stock Incentive Plan and the Rollover Options, for the year ended December 31, 2009:

	<u>Shares</u>	<u>Weighted Average Exercise Price</u>	<u>Aggregate Intrinsic Value(1) (in thousands)</u>
Outstanding at beginning of year January 1, 2009	645,348	\$ 13.88	\$ (1,462)
Granted	—	—	—
Exercised	(1,188)	11.59	—
Forfeited	—	—	—
Outstanding at end of year December 31, 2009	<u>644,160</u>	<u>\$ 13.88</u>	<u>\$ (1,462)</u>
Exercisable at end of year	644,160	\$ 13.88	\$ (1,462)

(1) Based upon the difference between the market price of the common stock on the last trading date of the year (\$11.61) and the option exercise price of in-the-money options.

The intrinsic value of options exercised in the years ended December 31, 2009, 2008 and 2007 was approximately \$3,000, \$(2.4) million and \$6.5 million, respectively, and the Company received approximately \$14,000, \$0.7 million and \$0.8 million, respectively, upon the exercise of such options and a windfall tax deduction of approximately \$3.1 million, \$0.3 million and \$0.4 million, respectively, in excess of previously recorded tax benefits, based on the option value at the time of grant. The windfalls are reflected in net operating loss carryforwards pursuant to GAAP, but the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable.

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The following table summarizes certain information about stock options outstanding under the Stock Incentive Plan and the Rollover Options at December 31, 2009:

Exercise Price	Options Outstanding		Options Exercisable	
	Shares Subject to Outstanding Options	Weighted Average Remaining Contractual Life (Years)	Expected Term	Weighted Average Shares Exercisable
\$9.67	660	4.08	6.08	660
\$11.44	1,650	4.88	6.88	1,650
\$11.59	29,045	4.75	6.94	29,045
\$14.00	612,805	5.25	10.50	612,805
Total number of shares subject to options	644,160			644,160

Options generally vested over one to three-year periods and are exercisable for periods ranging from seven to ten years. The weighted average fair value of options granted during 2006 was \$2.58. There were no options granted during 2007, 2008 or 2009. The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. The assumptions utilized in 2006 upon option grant are noted in the following table:

Black-Scholes Assumptions	12 Months Ended December 31, 2006
	Rollover Options
Expected Term (years)	4.7
Risk Free Interest Rate	4.79%
Expected Volatility	35.00%
Dividend Yield	0.00%

The expected term (estimated period of time outstanding) of options granted was determined by averaging the vesting period and contractual term. The expected volatility was based on historical volatility of the common share price of the peer group (identified above) for a period equal to the stock option's expected life. The risk-free rate is based on the U.S. Treasury-bill rate in effect at the time of grant. The dividend yield is based on the Company's ability to pay dividends.

Note 6. Employee Benefit and Royalty Plans

Employee Capital Accumulation Plan — The Company provides all full-time employees (who are at least 18 years of age) participation in the Employee Capital Accumulation Plan (the "Plan"), which is comprised of a contributory 401(k) savings plan and a discretionary profit sharing plan. Under the 401(k) feature, the Company, at its sole discretion, may contribute an employer-matching contribution equal to a percentage not to exceed 50% of each eligible participant's matched salary reduction contribution as defined by the Plan. Under the discretionary profit sharing contribution feature of the Plan, the Company's contribution, if any, must be determined annually and be 4% of the lesser of the Company's operating income or total employee compensation and be allocated to each eligible participant pro rata to his or her compensation. The Company expects to contribute approximately \$1.2 million for the year ended December 31, 2009, and contributed \$1.1 million and \$0.9 million for the years ended December 31, 2008 and 2007, respectively. Currently there are no plans to terminate the Plan.

Overriding Royalty Interests — Pursuant to agreements, certain employees and consultants of the Company are entitled to receive, as incentive compensation, overriding royalty interests ("Overriding Royalty

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Interests”) in certain oil and gas prospects acquired by the Company. Such Overriding Royalty Interests entitle the holder to receive a specified percentage of the gross proceeds from the future sale of oil and gas (less production taxes), if any, applicable to the prospects. Cash payments made by the Company to current employees and consultants with respect to Overriding Royalty Interests were \$2.1 million, \$3.6 million and \$5.8 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Note 7. Derivative Financial Instruments

The energy markets have historically been very volatile, and Mariner expects that oil and gas prices will be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of oil and natural gas on the Company’s operations, management has elected to hedge oil and natural gas prices from time to time through the use of commodity price swap agreements and costless collars. 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 the Company’s open contracts at the end of each period.

For derivative contracts that are designated and qualify as cash flow hedges pursuant to accounting for derivatives and hedging under GAAP, the portion of the gain or loss on the derivative instrument that is effective in offsetting the variable cash flows associated with the hedged forecasted transaction is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction in the same period or periods during which the hedged transaction affects earnings (e.g., in “revenues” when the hedged transactions are commodity sales). The remaining gain or loss on the derivative contract in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion) is recognized in earnings during the current period. The Company currently does not exclude any component of the derivative contracts’ gain or loss from the assessment of hedge effectiveness.

During 2009, the Company liquidated certain natural gas and crude oil fixed price swaps that previously had been designated as cash flow hedges for accounting purposes in respect of 10,205,560 million British thermal units of natural gas and 977,000 barrels of crude oil. The Company received \$58.7 million in conjunction with these liquidations and recognized natural gas and oil revenues of \$35.3 million and \$23.4 million, respectively.

Derivative gains and losses are recorded by commodity type in oil and gas revenues in the Consolidated Statements of Operations. The effects on the Company’s oil and gas revenues from its hedging activities were as follows:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Cash Gain (Loss) on Settlements(1)	\$ 173,684	\$ (98,814)	\$ 46,732
Gain (Loss) on Hedge Ineffectiveness(1)(2)	264	(1,995)	(1,655)
Reclassification of Liquidated Swaps(3)	58,710	—	—
Total	<u>\$ 232,658</u>	<u>\$ (100,809)</u>	<u>\$ 45,077</u>

- (1) Designated as cash flow hedges pursuant to accounting for derivatives and hedging under GAAP.
(2) Unrealized (loss) gain recognized in natural gas revenue related to the ineffective portion of open contracts that are not eligible for deferral under GAAP due primarily to the basis differentials between the contract price and the indexed price at the point of sale.

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- (3) Natural gas and crude oil fixed price swaps liquidated in the first and third quarters of 2009 that do not qualify for hedge accounting. These amounts include net losses of \$2.8 million for the year ended December 31, 2009.

As of December 31, 2009, the Company had the following hedging contracts outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price (In thousands)	Fair Value Asset/(Liability)
Natural Gas (MMbtus)			
January 1 — December 31, 2010	22,619,000	\$ 5.88	\$ 2,239
January 1 — December 31, 2011	13,650,000	\$ 6.45	1,540
January 1 — December 31, 2012	6,588,000	\$ 6.62	497
January 1 — December 31, 2013	5,840,000	\$ 6.76	410
Crude Oil (Bbls)			
January 1 — December 31, 2010	1,934,500	\$ 67.48	(27,708)
January 1 — December 31, 2011	978,100	\$ 73.24	(11,309)
January 1 — December 31, 2012	494,100	\$ 80.77	(3,058)
January 1 — December 31, 2013	408,800	\$ 82.81	(2,195)
Total			\$ (39,584)

As of December 31, 2008, the Company had the following hedging activity outstanding:

Fixed Price Swaps	Quantity	Weighted-Average Fixed Price (In thousands)	Fair Value Asset
Natural Gas (MMbtus)			
January 1 — December 31, 2009	31,642,084	\$ 8.48	\$ 74,709
Crude Oil (Bbls)			
January 1 — December 31, 2009	2,172,210	\$ 76.15	47,220
Total			\$ 121,929

The Company has reviewed the financial strength of its counterparties and believe the credit risk associated with these swaps to be minimal. Hedges with counterparties that are lenders under the Company's bank credit facility are secured under the bank credit facility.

For derivative instruments that are not designated as a hedge for accounting purposes, all realized and unrealized gains and losses are recognized in the statement of income during the current period. This will result in non-cash gains or losses being reported in Mariner's operating results.

As of December 31, 2009, the Company expects to realize within the next 12 months approximately \$25.5 million in net losses resulting from hedging activities currently recorded in accumulated other comprehensive income. The net hedging loss is expected to be realized as a decrease of \$27.7 million to oil revenues and an increase of \$2.2 million to natural gas revenues.

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Additional Disclosures about Derivative Instruments and Hedging Activities

At December 31, 2009, the Company had derivative financial instruments under GAAP recorded in its balance sheet as set forth below (in thousands):

Fair Value of Derivative Contracts				
Asset Derivatives				
December 31, 2009		December 31, 2008		
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	
Derivatives designated as cash flow hedging contracts				
Fixed Price Swaps		Current Assets: Derivative financial instruments		Current Assets: Derivative financial instruments
			\$ 2,239	\$ 121,929
		Long-Term Assets: Derivative Financial Instruments	902	
		Total	\$ 3,141	Total \$ 121,929

Fair Value of Derivative Contracts				
Liability Derivatives				
December 31, 2009		December 31, 2008		
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	
Derivatives designated as cash flow hedging contracts				
Fixed Price Swaps		Current Liabilities: Derivative financial instruments		Current Liabilities: Derivative financial instruments
			\$ 27,708	\$ —
		Long-Term Liabilities: Derivative financial instruments	15,017	—
		Total	\$ 42,725	Total \$ —

For the years ended December 31, 2009 and 2008, the effect on income of derivative financial instruments under GAAP was as follows (in thousands):

Derivatives Designated as Cash Flow Hedging Contracts Under GAAP	Amount of Gain/(Loss) Recognized in OCI on Derivative (Effective Portion)		Location of Gain/(Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	
	2009	2008		2009	2008		2009	2008
Fixed Price Swaps	\$ (39,584)	\$ 121,929	Revenues-Natural Gas	\$ 152,334	\$ (26,052)	Revenues-Natural Gas	\$ 264	\$ (1,995)
			Revenues-Crude Oil	21,350	(72,762)			
			Total	\$ 173,684	\$ (98,814)			

Derivatives not Designated as Cash Flow Hedging Contracts	Location of Gain/(Loss) Recognized in Income on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative	
		2009	2008
Fixed Price Swaps	Revenues-Natural Gas	\$ 35,259	\$ —
	Revenues-Crude Oil	23,451	—
	Total	\$ 58,710	\$ —

MARINER ENERGY, INC.**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007****Note 8. Commitments and Contingencies**

Minimum Future Lease Payments — The Company leases certain office facilities and other equipment under long-term operating lease arrangements. Minimum future lease obligations under the Company's operating leases in effect at December 31, 2009 are as follows (in thousands):

2010	2,577
2011	2,587
2012	2,502
2013	2,173
2014 and thereafter	9,959
Total	<u>\$ 19,798</u>

Rental expense, before capitalization, was approximately \$3.0 million for 2009, \$2.1 million for 2008 and \$1.4 million for 2007.

Other Commitments — In the ordinary course of business, the Company enters into long-term commitments to purchase seismic data and other geological information such as maps, logs and studies. The minimum annual payments under these commitments are \$1.6 million in 2010 and \$1.0 million in 2011.

Insurance Matters*Current Insurance Against Hurricanes*

Mariner is a member of OIL Insurance Limited ("OIL"), an energy industry insurance cooperative, which provides Mariner windstorm insurance coverage. During 2009, the coverage was subject to a \$10.0 million per-occurrence deductible, a \$250.0 million per-occurrence loss limit, and a \$750.0 million industry aggregate per-event loss limit. Effective January 1, 2010, the coverage is subject to a per-occurrence deductible which remains under consideration, a \$150.0 million per-occurrence loss limit per member, an annual maximum of \$300.0 million per member, and a \$750.0 million industry aggregate per-event loss limit. In addition, annual industry windstorm losses exceeding \$300.0 million will be mutualized among windstorm members in two pools, one for offshore and one for onshore, with future premiums based upon a pool's loss experience and a member's weighted percent of the pool's asset base. Mariner anticipates these changes to increase its loss retention by approximately \$100.0 million for windstorm losses, which it expects to either self insure, insure through the commercial market, insure through the purchase of additional OIL coverage or a combination of these.

Each year, Mariner considers whether to purchase from the commercial market supplemental or excess insurance which in the past has provided coverage when OIL limits have been exceeded (see discussion below under "— Hurricanes Katrina and Rita (2005)"). The supplemental insurance coverage offered by the commercial market in 2009 would not have provided similar coverage and Mariner elected not to purchase it when it expired on June 1, 2009. Mariner believes its assets are sufficiently insured through OIL and Mariner's expected ability to cover losses in excess of OIL coverage. Mariner intends to monitor the commercial market for insurance that would, based on Mariner's historical experience, cover its expected hurricane-related risks on a cost-effective basis once OIL limits are exceeded.

As of December 31, 2009, Mariner accrued approximately \$48.0 million for an OIL withdrawal premium contingency. As part of its OIL membership, Mariner is obligated to pay a withdrawal premium if it elects to withdraw from OIL. Mariner does not anticipate withdrawing from OIL; however, due to the contingency, Mariner periodically reassesses the sufficiency of its accrued withdrawal premium based on OIL's periodic

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For the Years Ended December 31, 2009, 2008 and 2007**

calculation of the potential withdrawal premium in light of past losses, and Mariner may adjust its accrual accordingly in the future. OIL requires smaller members to provide a letter of credit or other acceptable security in favor of OIL to secure payment of the withdrawal premium. Acceptable security has included a letter of credit or a security agreement pursuant to which a member grants OIL a security interest in certain claim proceeds payable by OIL to the member. Mariner has entered into such a security agreement, granting to OIL a senior security interest in up to the next \$50.0 million in excess of \$100.0 million of Mariner's Hurricane Ike claim proceeds payable by OIL. Mariner has the ability to replace the security agreement with a letter of credit or other acceptable security in favor of OIL.

Hurricane Ike (2008)

In 2008, the Company's operations were adversely affected by Hurricane Ike. The hurricane resulted in shut-in and delayed production as well as facility repairs and replacement expenses. The Company estimates that repairs and plugging and abandonment costs resulting from Hurricane Ike will total approximately \$160.0 million net to Mariner's interest. OIL has advised the Company that industry-wide damages from Hurricane Ike are expected to substantially exceed OIL's \$750.0 million industry aggregate per event loss limit and that OIL expects to initially prorate the payout of all OIL members' Hurricane Ike claims at approximately 50%, subject to further adjustment. OIL also has indicated that the scaling factor it expects to apply to Mariner's Hurricane Ike claims will result in settlement at less than 70%. Mariner expects that approximately 75% of the shortfall in its primary insurance coverage will be covered under its commercial excess coverage. In respect of Hurricane Ike claims that the Company made through December 2009, the Company received approximately \$30.6 million from OIL and \$9.7 million from excess carriers. Although in 2009 Mariner started receiving payment in respect of its Hurricane Ike claims, due to the magnitude of the storm and the complexity of the insurance claims being processed by the insurance industry, Mariner expects to maintain a potentially significant insurance receivable through 2010 while it actively pursues settlement.

Hurricanes Katrina and Rita (2005)

In 2005, the Company's operations were adversely affected by Hurricanes Katrina and Rita, resulting in substantial shut-in and delayed production, as well as necessitating extensive facility repairs and hurricane-related abandonment operations. Since 2005, the Company has incurred approximately \$208.6 million in hurricane expenditures resulting from Hurricanes Katrina and Rita, of which \$130.6 million were capitalized expenditures and \$78.0 million were hurricane-related abandonment costs.

Applicable insurance for the Company's Hurricane Katrina and Rita claims with respect to the Gulf of Mexico assets acquired in March 2006 was provided by OIL. Mariner's coverage for such properties was subject to a deductible of \$5.0 million per occurrence and a \$1.0 billion industry-wide loss limit per occurrence. OIL advised the Company that the aggregate claims resulting from each of Hurricanes Katrina and Rita were expected to exceed the \$1.0 billion per occurrence loss limit and that therefore Mariner's insurance recovery was expected to be reduced pro-rata (approximately 47% for Katrina and 67% for Rita) with all other competing claims from the storms. During 2008, the Company settled its Katrina and Rita claims with its excess insurers for a one-time cash payment of \$48.5 million.

As of December 31, 2009, the Company had recovered approximately \$137.0 million in respect of Hurricanes Katrina and Rita, of which \$88.5 million was paid by OIL and \$48.5 million was paid by excess insurers. Although the Company has received full and final settlement of its insurance claims in respect of Hurricanes Katrina and Rita as of December 31, 2009, it may receive from OIL a relatively immaterial additional amount in respect of Hurricane Rita after OIL finally adjusts all of its members' Hurricane Rita claims.

MARINER ENERGY, INC.**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007**

MMS Proceedings — Mariner and its subsidiary, Mariner Energy Resources, Inc. (“MERI”), own numerous properties in the Gulf of Mexico. Certain of such properties were leased from the MMS subject to RRA. Section 304 of the RRA relieves lessees of the obligation to pay royalties on certain leases until after a designated volume has been produced. Four of these leases held by Mariner and two held by MERI that are producing or have produced contain lease language (inserted by the MMS) that conditions royalty relief on commodity prices remaining below specified thresholds. Since 2000, commodity prices have exceeded some of the predetermined thresholds, except in 2002. In May 2006, September 2008 and August 2009, the MMS issued orders asserting that the price thresholds had been exceeded in calendar years 2000, 2001, and each of the years from 2003 through 2008, and, accordingly, that royalties were due under such leases on oil and gas produced in those years (the “Orders”). Mariner and MERI believed that the MMS did not have the statutory authority to include commodity price threshold language in the leases governed by Section 304 of the RRA, withheld payment of royalties, and challenged the MMS’s authority in administrative appeals respecting those leases subject to the Orders. In February 2010, the MMS notified the Company that the MMS withdrew the Orders, rendering the Company’s appeals moot and closing the matter in the Company’s favor.

The enforceability of the price threshold provisions in leases granted pursuant to Section 304 of the RRA was being litigated in several administrative appeals filed by other companies in addition to the Company, as well as in *Kerr-McGee Oil & Gas Corp. v. Allred*, 554 F.3d 1082 (5th Cir.), *cert denied*, *Dep’t of the Interior v. Kerr-McGee Oil & Gas Corp.*, 130 S. Ct. 236 (2009). In the *Kerr-McGee* litigation, the district court in the Western District of Louisiana granted Kerr-McGee’s motion for summary judgment, ruling that the price threshold provisions are unlawful and unenforceable under Section 304 of the RRA. *Kerr-McGee Oil & Gas Corp. v. Allred*, No. 2:06 CV 0439 (W.D. La.) (Mem. Ruling filed Oct. 30, 2007). The Department of the Interior (“DOI”) appealed that judgment to the United States Court of Appeals for the Fifth Circuit. On January 12, 2009, the Fifth Circuit affirmed the district court’s judgment that the price provisions are unlawful based on Section 304 of the RRA. On April 14, 2009, the Fifth Circuit denied the DOI’s Petition for Rehearing En Banc. On July 13, 2009, the DOI filed a Petition for a Writ of Certiorari with the Supreme Court of the United States. On October 5, 2009, the U.S. Supreme Court denied the Petition for a Writ of Certiorari. Accordingly, the Fifth Circuit’s judgment that the price threshold provisions are unlawful and unenforceable under Section 304 of the RRA is final. This judgment was the basis upon which the MMS withdrew the Orders.

Litigation — The Company, in the ordinary course of business, is a claimant and/or a defendant in various legal proceedings, including proceedings as to which the Company has insurance coverage and those that may involve the filing of liens against the Company or its assets. The Company does not consider its exposure in these proceedings, individually or in the aggregate, to be material.

Letters of Credit — Mariner’s bank credit facility has a letter of credit subfacility of up to \$50 million that is included as a use of the borrowing base. As of December 31, 2009, four such letters of credit totaling \$4.7 million were outstanding of which \$4.2 million is required for plugging and abandonment obligations at certain of Mariner’s offshore fields.

Note 9. Fair Value Measurement

Certain of Mariner’s assets and liabilities are reported at fair value in the accompanying Consolidated Balance Sheets. Such assets and liabilities include amounts for both financial and nonfinancial instruments. The carrying values of cash and cash equivalents, accounts receivable and accounts payable (including income taxes payable and accrued expenses) approximated fair value at December 31, 2009 and December 31, 2008. These assets and liabilities are not included in the following tables.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the table below, the hierarchy consists of three broad levels. Level 1 inputs

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are market-based and are directly or indirectly observable but not considered Level 1 quoted prices, including quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; or valuation techniques whose inputs are observable. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Level 3 inputs are unobservable (meaning they reflect Mariner's own assumptions regarding how market participants would price the asset or liability based on the best available information) and therefore have the lowest priority. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Mariner believes it uses appropriate valuation techniques based on the available inputs to measure the fair values of its assets and liabilities.

GAAP requires a credit adjustment for non-performance in calculating the fair value of financial instruments. The credit adjustment for derivatives in an asset position is determined based on the credit rating of the counterparty and the credit adjustment for derivatives in a liability position is determined based on Mariner's credit rating.

The following table provides fair value measurement information for the Company's derivative financial instruments as of December 31, 2009.

Derivative Financial Instruments	As of December 31, 2009			
	Total Fair Value	Fair Value Measurements Using:		
		Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(In thousands)		
Natural gas and crude oil fixed price swaps — Short Term	\$ 25,469	\$ —	\$ 25,469	\$ —
Natural gas and crude oil fixed price swaps — Long Term	14,115	—	14,115	—
Total	\$ 39,584	\$ —	\$ 39,584	\$ —

The following methods and assumptions were used to estimate the fair values of Mariner's derivative financial instruments in the table above.

Level 2 Fair Value Measurements

The fair values of the natural gas and crude oil fixed price swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves, terms of each contract, and a credit adjustment based on the credit rating of the Company and its counterparties as of December 31, 2009.

Level 3 Fair Value Measurements

The Company had no Level 3 financial instruments as of December 31, 2009.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of accounting for financial instruments under GAAP, which Mariner adopted effective March 31, 2009 as described in Note 1 "Summary of Significant Accounting Policies." The estimated fair value amounts have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying amounts and fair values of the Company's long-term debt are as follows:

Long-term Debt	September 30, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Bank credit facility	\$ 305,000	\$ 305,000	\$ 570,000	\$ 570,000
7 1/2% Notes, net of discount	298,125	233,770	300,000	144,956
8% Notes	300,000	168,519	300,000	59,978
11 3/4% Notes, net of discount	291,725	163,650	—	—
Total long-term debt	\$ 1,194,850	\$ 870,939	\$ 1,170,000	\$ 774,934

The fair value of the amounts outstanding under the bank credit facility as of December 31, 2009 is based on rates currently available for debt instruments with similar terms and average maturities from companies with similar credit ratings in the industry. The fair value of the Notes is based on quoted market prices based on trades of such debt as of December 31, 2009.

Note 10. Income Taxes

The components of the federal income tax provision are:

	For the Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Current	\$ (107)	\$ 1,939	\$ —
Deferred	(224,263)	(50,162)	77,324
Total (Benefit) Provision for Income Taxes	\$ (224,370)	\$ (48,223)	\$ 77,324

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

	Year Ended December 31,					
	2009		2008		2007	
	(In thousands, except percentages)					
(Loss) Income before taxes	\$ (543,779)		\$ (436,748)		\$ 221,259	
Income tax expense computed at statutory rates	(190,323)	35.0%	(152,862)	35.0%	77,440	35.0%
State tax expense, net of the federal benefit	(5,307)	1.0%	(619)	0.2%	2,452	1.1%
Acquisition purchase price adjustment	—	—	—	—	(2,034)	(0.9)%
Share-based compensation shortfall (ACS 718)	9,887	(1.8)%	—	—	—	—
Gain on acquisition	(37,552)	6.9%	—	—	—	—
Goodwill impairment	—	—	103,460	(23.7)%	—	—
Other	(1,075)	0.2%	1,798	(0.5)%	(534)	(0.3)%
Total (Benefit) Provision for Income Taxes	\$ (224,370)	41.3%	\$ (48,223)	11.0%	\$ 77,324	34.9%

MARINER ENERGY, INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

Federal income taxes refunded to the Company in the year ended December 31, 2009 were \$2.2 million. Federal income taxes paid by the Company in the year ended December 31, 2008 and 2007 were \$2.9 million and \$0.6 million, respectively.

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

	At December 31,	
	2009	2008
	(In thousands)	
Current Deferred Tax Assets:		
Employee share-based compensation	\$ 782	\$ 2,484
Other comprehensive income-derivative instruments	8,922	—
Net operating loss carryforwards (current)	—	17,591
Total current deferred tax assets	<u>9,704</u>	<u>20,075</u>
Long-Term Deferred Tax Assets:		
Net operating loss carryforwards	242,068	154,711
Alternative minimum tax credit	3,152	3,342
Valuation allowance	(223)	(408)
Other comprehensive income-derivative instruments	4,972	—
Reserve accruals	5,890	439
Other	395	4,499
Total long-term deferred tax assets	<u>256,254</u>	<u>162,583</u>
Current Deferred Tax Liabilities:		
Deferred gain	—	—
Other comprehensive income-derivative instruments	—	(43,223)
Other	—	—
Total current deferred tax liabilities	<u>—</u>	<u>(43,223)</u>
Long-Term Deferred Tax Liabilities:		
Deferred gain	—	—
Other comprehensive income-derivative instruments	—	—
Differences between book and tax basis properties	(238,218)	(472,718)
Texas margins tax	(1,254)	(98)
Louisiana franchise tax	(4,291)	(9,533)
Other	—	—
Total long-term deferred tax liabilities	<u>(243,763)</u>	<u>(482,349)</u>
Total net deferred asset (liability)	<u>\$ 22,195</u>	<u>\$ (342,914)</u>

At December 31, 2009, the Company had federal and state net operating loss carryforwards of approximately \$691.0 million and \$17.3 million, respectively, which will expire in varying amounts between 2018 and 2034 and are subject to certain limitations on an annual basis. A valuation allowance has been established against state net operating losses where it is more likely than not that such losses will expire before they are utilized.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

In prior years, the Company incurred changes of control as defined by the Internal Revenue Code Section 382 (“Section 382”). Accordingly, the rules of Section 382 will limit the utilization of the Company’s net operating losses. The limitation is determined by multiplying the value of the stock immediately before the ownership change by the applicable long-term exempt rate. It is estimated that \$47.2 million of net operating losses will be subject to an annual limitation of approximately \$4.0 million, and an estimated \$87.2 million of net operating losses will be subject to an annual limitation of approximately \$33.0 million. Any unused annual limitation may be carried over to later years. The amount of the limitation may under certain circumstances be increased by the built-in gains in assets held by the Company at the time of the change that are recognized in the five-year period after the change.

The Company’s federal net operating loss carryforwards include the addition of estimated tax attributes in connection with the acquisition of the reorganized Edge subsidiaries on December 31, 2009. The transaction was structured as a subsidiary stock purchase which enabled the Company to carryover the tax attributes of the Edge subsidiaries. The Edge subsidiaries’ federal net operating loss carryforwards are estimated to be \$174.8 million, and these acquired losses are subject to certain annual limitations as defined by Section 382. The Section 382 limitation in connection with the Edge acquisition is approximately \$8.8 million per year. The Company currently estimates no benefit associated with state net operating loss carryforwards in connection with acquisition. The acquisition of Edge also resulted in the addition of approximately \$87.1 million of built-in losses associated with the tax basis in the properties of the subsidiaries. These built-in losses are also subject to limitations as defined by Section 382. These built-in losses are reflected in the Company’s long-term deferred tax liabilities under the caption differences between book and tax basis in properties.

The Company adopted amended authoritative guidance which clarified the accounting and disclosure for uncertainty in tax positions, as defined. The guidance seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. The Company adopted and applied the guidance as of January 1, 2007. As of the adoption date, the Company did not record a cumulative effect adjustment related to the adoption or have any gross unrecognized tax benefit. At December 31, 2009, the Company did not have any liability or gross recognized tax benefit.

Deferred tax assets relating to tax benefits of employee share-based compensation have been reduced to reflect stock options exercised and restricted stock that vested in fiscal 2009. Some exercises and vestings result in tax deductions in excess of previously recorded benefits based on the option value at the time of grant (“windfalls”). Although these additional tax benefits or “windfalls” are reflected in net operating tax carryforwards pursuant to accounting for stock compensation under GAAP, the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable. Accordingly, since the tax benefit does not reduce the Company’s current taxes payable in fiscal 2009 due to net operating loss carryforwards, these “windfall” tax benefits are not reflected in the Company’s net operating losses in deferred tax assets for fiscal 2009. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for fiscal 2009 are \$9.2 million. Any shortfalls resulting from tax deductions that were less than the previously-recorded benefits were recorded as increases to income tax expense during fiscal 2009.

Note 11. Segment Information

The FASB issued authoritative guidance establishing standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses. Separate financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

Mariner measures financial performance as a single enterprise, allocating capital resources on a project-by-project basis across its entire asset base to maximize profitability. The Company utilizes a company-wide management team that administers all enterprise operations encompassing the exploration, development and production of natural gas and oil. Since Mariner follows the full cost method of accounting and all of its oil and gas properties and operations are located in the United States, the Company has determined that it has one reporting unit. Inasmuch as Mariner is one enterprise, the Company does not maintain comprehensive financial statement information by area but does track basic operational data by area.

Note 12. Quarterly Financial Information (Unaudited)

The following table presents Mariner's unaudited quarterly financial information for 2009 and 2008:

	Quarter Ended 2009			
	December 31	September 30	June 30	March 31
(In thousands, except share data)				
Total revenues	\$ 240,289	\$ 227,346	\$ 231,970	\$ 243,336
Operating (loss) income(1)	(17,493)	26,814	52,411	(643,135)
Income (Loss) before taxes(1)	70,764	7,168	35,741	(657,452)
Provision (Benefit) for income taxes(1)	(12,510)	2,946	18,528	(233,334)
Net income (loss) attributable to Mariner Energy, Inc.(1)	\$ 83,274	\$ 4,222	\$ 17,213	\$ (424,118)
Earnings per share:(3)				
Net income (loss) per share — basic	\$ 0.83	\$ 0.04	\$ 0.19	\$ (4.77)
Net income (loss) per share — diluted	\$ 0.82	\$ 0.04	\$ 0.19	\$ (4.77)
Weighted average shares outstanding — basic	100,825,884	100,752,532	91,798,761	88,864,648
Weighted average shares outstanding — diluted	101,406,275	101,084,502	92,152,933	88,864,648
Quarter Ended 2008				
	December 31	September 30	June 30	March 31
(In thousands, except share data)				
Total revenues	\$ 237,268	\$ 317,890	\$ 429,452	\$ 315,897
Operating (loss) income(2)	(839,221)	117,668	208,186	131,655
(Loss) Income before taxes(2)	(841,592)	100,530	190,904	113,410
(Benefit) Provision for income taxes(3)	(192,672)	35,839	67,416	41,194
Net (loss) income(2)	(648,920)	64,691	123,488	72,216
Net income attributable to noncontrolling interest	—	—	98	90
Net (loss) income attributable to Mariner Energy, Inc.(2)	\$ (648,920)	\$ 64,691	\$ 123,390	\$ 72,126
Earnings per share:(3)				
Net (loss) income per share — basic	\$ (7.41)	\$ 0.74	\$ 1.40	\$ 0.83

Net (loss) income per share — diluted	\$ (7.41)	\$ 0.73	\$ 1.39	\$ 0.82
Weighted average shares outstanding — basic	87,622,740	87,595,792	87,983,902	87,293,730
Weighted average shares outstanding — diluted	87,622,740	88,183,715	88,828,904	88,012,901

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

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- (1) There are no operating results for the Edge subsidiaries acquired by the Company on December 31, 2009. Fourth quarter amounts include a bargain purchase gain of \$107.3 million related to the acquisition of the Edge subsidiaries and a full cost ceiling test impairment of \$49.6 million. First quarter amounts include a full cost ceiling test impairment of \$704.7 million.
 - (2) Fourth quarter amounts include \$575.6 million in full cost ceiling test impairment, \$295.6 million in goodwill impairment, \$15.3 million in other property impairment, \$21.6 million in retrospective contingent OIL insurance premium, and \$46.5 million release of suspended revenue associated with the disputed MMS Royalty Relief liability.
 - (3) The sum of quarterly net income per share may not agree with total year net income per share, as each quarterly computation is based on the weighted average shares outstanding.

Note 13. Supplemental Guarantor Information

On June 10, 2009, the Company sold and issued \$300.0 million aggregate principal amount of its 11^{3/4}% Notes. On April 30, 2007, the Company sold and issued \$300 million aggregate principal amount of its 8% Notes. On April 24, 2006, the Company sold and issued to eligible purchasers \$300 million aggregate principal amount of its 7^{1/2}% Notes. The Notes are jointly and severally guaranteed on a senior unsecured basis by the Company's existing and certain of its future domestic subsidiaries ("Subsidiary Guarantors"). The guarantees are full and unconditional and the guarantors are wholly-owned. In the future, the guarantees may be released or terminated under certain circumstances.

The following information sets forth Mariner's Consolidating Balance Sheets as of December 31, 2009 and 2008, its Condensed Consolidating Statements of Operations for the years ended December 31, 2009, 2008 and 2007, and its Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007.

Mariner accounts for investments in its subsidiaries using the equity method of accounting; accordingly, entries necessary to consolidate Mariner, the parent company, and its Subsidiary Guarantors are reflected in the eliminations column.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

MARINER ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEET
December 31, 2009
(In thousands except share data)

	Parent Company	Subsidiary Guarantors	Subsidiary Non- Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Current Assets:					
Cash and cash equivalents	\$ 8,365	\$ 3	\$ 551	\$ —	\$ 8,919
Receivables, net of allowances	94,958	53,767	—	—	148,725
Insurance receivables	74	8,378	—	—	8,452
Derivative financial instruments	2,239	—	—	—	2,239
Intangible assets	22,615	—	—	—	22,615
Prepaid expenses and other	10,450	1,217	—	—	11,667
Deferred income tax	9,704	—	—	—	9,704
Total current assets	148,405	63,365	551	—	212,321
Property and Equipment:					
Proved oil and gas properties, full cost method	2,472,963	2,644,310	—	—	5,117,273
Unproved properties, not subject to amortization	246,037	46,134	66	—	292,237
Total oil and gas properties	2,719,000	2,690,444	66	—	5,409,510
Other property and equipment	19,926	35,358	411	—	55,695
Accumulated depreciation, depletion and amortization:					
Proved oil and gas properties	(1,499,787)	(1,384,624)	—	—	(2,884,411)
Other property and equipment	(6,145)	(2,090)	—	—	(8,235)
Accumulated depreciation, depletion and amortization	(1,505,932)	(1,386,714)	—	—	(2,892,646)
Total property and equipment, net	1,232,994	1,339,088	477	—	2,572,559
Investment in Subsidiaries	715,772	—	—	(715,772)	—
Intercompany Receivables	222,273	—	—	(222,273)	—
Intercompany Note Receivable	7,175	—	—	(7,175)	—
Insurance Receivables	—	—	—	—	—
Derivative Financial Instruments	902	—	—	—	902
Deferred Income Tax	35,583	(23,092)	—	—	12,491
Other Assets, net of amortization	68,631	301	—	—	68,932
TOTAL ASSETS	\$ 2,431,735	\$ 1,379,662	\$ 1,028	\$ (945,220)	\$ 2,867,205
Current Liabilities:					
Accounts payable	\$ 3,569	\$ —	\$ 10	\$ —	\$ 3,579
Accrued liabilities	107,537	29,669	—	—	137,206
Accrued capital costs	71,420	69,521	—	—	140,941
Deferred income tax	—	—	—	—	—
Abandonment liability	10,632	44,283	—	—	54,915
Accrued interest	8,262	—	—	—	8,262
Derivative financial instruments	27,708	—	—	—	27,708
Total current liabilities	229,128	143,473	10	—	372,611
Long-Term Liabilities:					
Abandonment liability	71,320	291,652	—	—	362,972
Deferred income tax	—	—	—	—	—
Intercompany payables	—	222,273	—	(222,273)	—
Derivative Financial Instruments	15,017	—	—	—	15,017
Long-term debt	1,194,850	—	—	—	1,194,850
Other long-term liabilities	38,458	342	—	—	38,800
Intercompany note payable	—	7,175	—	(7,175)	—
Total long-term liabilities	1,319,645	521,442	—	(229,448)	1,611,639
Commitments and Contingencies (see Note 8)					
Stockholders' Equity:					
Preferred stock, \$.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2009	—	—	—	—	—
Common stock, \$.0001 par value; 180,000,000 shares authorized, 101,806,825 shares issued and outstanding at December 31, 2009	10	5	—	(5)	10
Additional paid-in-capital	1,257,526	1,098,156	1,538	(1,099,694)	1,257,526
Partner capital	—	33,019	—	(33,019)	—
Accumulated other comprehensive loss	(25,948)	—	(7)	—	(25,955)
Accumulated retained deficit	(348,626)	(416,433)	(513)	416,946	(348,626)
Total stockholders' equity	882,962	714,747	1,018	(715,772)	882,955
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 2,431,735	\$ 1,379,662	\$ 1,028	\$ (945,220)	\$ 2,867,205

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

MARINER ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING BALANCE SHEET
December 31, 2008
(In thousands except share data)

	Parent Company	Subsidiary Guarantors	Eliminations	Consolidated Mariner Energy, Inc.
Current Assets:				
Cash and cash equivalents	\$ 2,851	\$ 400	\$ —	\$ 3,251
Receivables, net of allowances	157,362	62,558	—	219,920
Insurance receivables	5,886	7,237	—	13,123
Derivative financial instruments	121,929	—	—	121,929
Intangible assets	2,334	19	—	2,353
Prepaid expenses and other	12,923	1,454	—	14,377
Total current assets	303,285	71,668	—	374,953
Property and Equipment:				
Proved oil and gas properties, full cost method	2,181,238	2,266,908	—	4,448,146
Unproved properties, not subject to amortization	185,012	16,109	—	201,121
Total oil and gas properties	2,366,250	2,283,017	—	4,649,267
Other property and equipment	33,351	19,764	—	53,115
Accumulated depreciation, depletion and amortization:				
Proved oil and gas properties	(911,462)	(855,566)	—	(1,767,028)
Other property and equipment	(4,425)	(1,052)	—	(5,477)
Accumulated depreciation, depletion and amortization	(915,887)	(856,618)	—	(1,772,505)
Total property and equipment, net	1,483,714	1,446,163	—	2,929,877
Investment in Subsidiaries	704,971	—	(704,971)	—
Intercompany Receivables	123,142	113,064	(236,206)	—
Intercompany Note Receivable	176,200	—	(176,200)	—
Insurance Receivables	3,924	18,208	—	22,132
Other Assets, net of amortization	64,726	1,105	—	65,831
TOTAL ASSETS	\$ 2,859,962	\$ 1,650,208	\$ (1,117,377)	\$ 3,392,793
Current Liabilities:				
Accounts payable	\$ 3,837	\$ —	\$ —	\$ 3,837
Accrued liabilities	72,743	35,072	—	107,815
Accrued capital costs	144,710	51,123	—	195,833
Deferred income tax	23,148	—	—	23,148
Abandonment liability	1,554	80,810	—	82,364
Accrued interest	12,567	—	—	12,567
Total current liabilities	258,559	167,005	—	425,564
Long-Term Liabilities:				
Abandonment liability	56,920	268,960	—	325,880
Deferred income tax	110,431	209,335	—	319,766
Intercompany payables	113,064	123,142	(236,206)	—
Long-term debt	1,170,000	—	—	1,170,000
Other long-term liabilities	30,668	595	—	31,263
Intercompany Note Payable	—	176,200	(176,200)	—
Total long-term liabilities	1,481,083	778,232	(412,406)	1,846,909
Commitments and Contingencies (see Note 8)				
Stockholders' Equity:				
Preferred stock, \$.0001 par value; 20,000,000 shares authorized, no shares issued and outstanding at December 31, 2008	—	—	—	—
Common stock, \$.0001 par value; 180,000,000 shares authorized, 88,846,073 shares issued and outstanding at December 31, 2008	9	5	(5)	9
Additional paid-in-capital	1,071,347	886,143	(886,143)	1,071,347
Partner capital	—	30,646	(30,646)	—
Accumulated other comprehensive income	78,181	—	—	78,181
Accumulated retained deficit	(29,217)	(211,823)	211,823	(29,217)
Total stockholders' equity	1,120,320	704,971	(704,971)	1,120,320
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 2,859,962	\$ 1,650,208	\$ (1,117,377)	\$ 3,392,793

MARINER ENERGY, INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007
MARINER ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2009
(In thousands)

	<u>Parent Company</u>	<u>Subsidiary Guarantors</u>	<u>Subsidiary Non- Guarantors</u>	<u>Eliminations</u>	<u>Consolidated Mariner Energy, Inc.</u>
Revenues:					
Natural gas	\$ 401,520	\$ 150,739	\$ —	\$ —	\$ 552,259
Oil	221,825	93,817	—	—	315,642
Natural gas liquids	37,440	11,481	—	—	48,921
Other revenues	8,339	17,780	—	—	26,119
Total revenues	<u>669,124</u>	<u>273,817</u>	<u>—</u>	<u>—</u>	<u>942,941</u>
Costs and Expenses:					
Operating expenses	154,913	127,440	—	—	282,353
General and administrative expense	78,158	1,289	513	—	79,960
Depreciation, depletion and amortization	231,095	168,305	—	—	399,400
Full cost ceiling test impairment	363,946	390,379	—	—	754,325
Other miscellaneous expense	6,530	1,776	—	—	8,306
Total costs and expenses	<u>834,642</u>	<u>689,189</u>	<u>513</u>	<u>—</u>	<u>1,524,344</u>
OPERATING LOSS	(165,518)	(415,372)	(513)	—	(581,403)
Loss of Affiliates	(205,123)	—	—	205,123	—
Other Income/(Expense):					
Interest income	3,981	—	—	(3,482)	499
Interest expense, net of amounts capitalized	(70,001)	(3,615)	—	3,482	(70,134)
Gain on acquisition	—	107,259	—	—	107,259
Loss Before Taxes	(436,661)	(311,728)	(513)	205,123	(543,779)
Benefit for Income Taxes	117,252	107,118	—	—	224,370
NET LOSS	<u>\$ (319,409)</u>	<u>\$ (204,610)</u>	<u>\$ (513)</u>	<u>\$ 205,123</u>	<u>\$ (319,409)</u>

MARINER ENERGY, INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007
MARINER ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2008
(In thousands)

	<u>Parent Company</u>	<u>Subsidiary Guarantors</u>	<u>Eliminations</u>	<u>Consolidated Mariner Energy, Inc.</u>
Revenues:				
Natural gas	\$ 358,585	\$ 383,785	\$ —	\$ 742,370
Oil	239,842	180,036	—	419,878
Natural gas liquids	56,307	29,408	—	85,715
Other revenues	41,851	10,693	—	52,544
Total revenues	<u>696,585</u>	<u>603,922</u>	<u>—</u>	<u>1,300,507</u>
Costs and Expenses:				
Operating expenses	137,917	126,915	—	264,832
General and administrative	58,617	1,996	—	60,613
Depreciation, depletion and amortization	251,783	215,482	—	467,265
Full cost ceiling test impairment	266,326	309,281	—	575,607
Goodwill impairment	—	295,598	—	295,598
Other property impairment	—	15,252	—	15,252
Other miscellaneous expense	2,538	514	—	3,052
Total costs and expenses	<u>717,181</u>	<u>965,038</u>	<u>—</u>	<u>1,682,219</u>
OPERATING LOSS	(20,596)	(361,116)	—	(381,712)
Earnings of Affiliates	(334,223)	—	334,223	—
Other Income/(Expenses):				
Interest income	10,239	84	(8,961)	1,362
Interest expense, net of amounts capitalized	(56,206)	(9,153)	8,961	(56,398)
Loss Before Taxes	(400,786)	(370,185)	334,223	(436,748)
Benefit for Income Taxes	12,073	36,150	—	48,223
NET LOSS	(388,713)	(334,035)	334,223	(388,525)
Less: Net income attributable to noncontrolling interest	—	(188)	—	(188)
NET LOSS ATTRIBUTABLE TO MARINER ENERGY, INC	<u>\$ (388,713)</u>	<u>\$ (334,223)</u>	<u>\$ 334,223</u>	<u>\$ (388,713)</u>

MARINER ENERGY, INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007
MARINER ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
Year Ended December 31, 2007
(In thousands)

	<u>Parent Company</u>	<u>Subsidiary Guarantors</u>	<u>Eliminations</u>	<u>Consolidated Mariner Energy, Inc.</u>
Revenues:				
Natural gas	\$ 266,418	\$ 268,119	\$ —	\$ 534,537
Oil	146,909	137,496	—	284,405
Natural gas liquids	30,513	23,679	—	54,192
Other revenues	1,491	140	—	1,631
Total revenues	<u>445,331</u>	<u>429,434</u>	<u>—</u>	<u>874,765</u>
Costs and Expenses:				
Operating expenses	59,232	106,377	—	165,609
General and administrative	43,004	8,060	—	51,064
Depreciation, depletion and amortization	175,147	209,174	—	384,321
Other miscellaneous expense	2,010	3,051	—	5,061
Total costs and expenses	<u>279,393</u>	<u>326,662</u>	<u>—</u>	<u>606,055</u>
OPERATING INCOME	165,938	102,772	—	268,710
Earnings of Affiliates	63,440		(63,440)	—
Other Income/(Expenses):				
Interest income	15,611	15	(14,223)	1,403
Interest expense, net of amounts capitalized	(54,302)	(14,586)	14,223	(54,665)
Other income	—	5,811	—	5,811
Income Before Taxes	190,687	94,012	(63,440)	221,259
Provision for Income Taxes	(46,753)	(30,571)	—	(77,324)
NET INCOME	143,934	63,441	(63,440)	143,935
Less: Net income attributable to noncontrolling interest	—	(1)	—	(1)
NET INCOME ATTRIBUTABLE TO MARINER ENERGY, INC	\$ 143,934	\$ 63,440	\$ (63,440)	\$ 143,934

MARINER ENERGY, INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007
MARINER ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
Year Ended December 31, 2009
(In thousands)

	<u>Parent Company</u>	<u>Subsidiary Guarantors</u>	<u>Subsidiary Non- Guarantors</u>	<u>Eliminations</u>	<u>Consolidated Mariner Energy, Inc.</u>
Net cash provided by operating activities	\$ 467,342	\$ 110,828	\$ (503)	\$ —	\$ 577,667
Cash flow from investing activities:					
Acquisitions and additions to oil and gas properties	(375,653)	(155,230)	(66)	—	(530,949)
Acquisitions of subsidiaries of Edge Petroleum Corporation	(213,553)	—	—	—	(213,553)
Additions to other property and equipment	(2,195)	—	(411)	—	(2,606)
Repayments of notes from affiliates	169,025	—	—	(169,025)	—
Other investing activities	—	—	—	—	—
Net cash used in investing activities	<u>(422,376)</u>	<u>(155,230)</u>	<u>(477)</u>	<u>(169,025)</u>	<u>(747,108)</u>
Cash flow from financing activities:					
Credit facility borrowings	710,221	—	—	—	710,221
Credit facility repayments	(975,221)	—	—	—	(975,221)
Repayments of notes to affiliates	—	(169,025)	—	169,025	—
Other financing activities	<u>225,548</u>	<u>213,030</u>	<u>1,531</u>	<u>—</u>	<u>440,109</u>
Net cash (used in) provided by financing activities	<u>(39,452)</u>	<u>44,005</u>	<u>1,531</u>	<u>169,025</u>	<u>175,109</u>
Increase (Decrease) in Cash and Cash Equivalents	5,514	(397)	551	—	5,668
	2,851	400	—	—	3,251

**Cash and Cash
Equivalents at
Beginning of
Period**

Cash and Cash Equivalents at End of Period	<u>\$ 8,365</u>	<u>\$ 3</u>	<u>\$ 551</u>	<u>\$ —</u>	<u>\$ 8,919</u>
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MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
Year Ended December 31, 2008
(In thousands)

	Parent Company	Subsidiary Guarantors	Consolidated Mariner Energy, Inc.
Net cash provided by operating activities	\$ 430,526	\$ 431,491	\$ 862,017
Cash flow from investing activities:			
Acquisitions and additions to oil and gas properties	(793,948)	(426,119)	(1,220,067)
Additions to other property and equipment	(15,099)	(34,618)	(49,717)
Other investing activities	—	5,000	5,000
Net cash used in investing activities	(809,047)	(455,737)	(1,264,784)
Cash flow from financing activities:			
Credit facility borrowings	1,268,000	—	1,268,000
Credit facility repayments	(877,000)	—	(877,000)
Other financing activities	(28,217)	24,646	(3,571)
Net cash provided by financing activities	362,783	24,646	387,429
(Decrease) Increase in Cash and Cash Equivalents	(15,738)	400	(15,338)
Cash and Cash Equivalents at Beginning of Period	18,589	—	18,589
Cash and Cash Equivalents at End of Period	\$ 2,851	\$ 400	\$ 3,251

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

MARINER ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
Year Ended December 31, 2007
(In thousands)

	Parent Company	Subsidiary Guarantors	Consolidated Mariner Energy, Inc.
Net cash provided by operating activities	\$ 282,664	\$ 253,450	\$ 536,114
Cash flow from investing activities:			
Acquisitions and additions to property and equipment	(527,926)	(146,786)	(674,712)
Property conveyances	2,988	1,114	4,102
Other investing activities	26,830	—	26,830
Net cash used in investing activities	(498,108)	(145,672)	(643,780)
Cash flow from financing activities:			
Credit facility borrowings	564,000	—	564,000
Credit facility repayments	(739,000)	—	(739,000)
Proceeds from note offering	300,000	—	300,000
Other financing activities	99,454	(107,778)	(8,324)
Net cash provided by (used in) financing activities	224,454	(107,778)	116,676
Increase in Cash and Cash Equivalents	9,010	—	9,010
Cash and Cash Equivalents at Beginning of Period	9,579	—	9,579
Cash and Cash Equivalents at End of Period	\$ 18,589	\$ —	\$ 18,589

Note 14. Subsequent Events

The Company's evaluation has identified no matters which required disclosure as a subsequent event.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

Note 15. Oil and Gas Producing Activities and Capitalized Costs (Unaudited)

The results of operations from the Company's oil and gas producing activities below exclude non-oil and gas revenues, general and administrative expenses, interest income and interest expense. Income tax expense was determined by applying the statutory rates to pretax operating results.

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Oil and gas sales	\$ 916,822	\$ 1,247,963	\$ 873,134
Lease operating costs	(249,449)	(231,644)	(152,627)
Severance and ad valorem taxes	(14,410)	(18,191)	(13,101)
Transportation	(18,494)	(14,996)	(8,794)
Depreciation, depletion and amortization	(396,641)	(463,989)	(383,154)
Full cost ceiling test impairment	(754,325)	(575,607)	—
Income tax benefit (expense)	180,774	20,214	(110,095)
Results of operations	<u>\$ (335,723)</u>	<u>\$ (36,250)</u>	<u>\$ 205,363</u>

The following table summarizes the Company's capitalized costs of oil and gas properties.

	At December 31,		
	2009	2008	2007
	(In thousands)		
Unevaluated properties, not subject to amortization	\$ 292,237	\$ 201,121	\$ 40,455
Properties subject to amortization	5,117,273	4,448,146	3,118,273
Capitalized costs	5,409,510	4,649,267	3,158,728
Accumulated depreciation, depletion and amortization	(2,884,411)	(1,767,027)	(751,126)
Net capitalized costs	<u>\$ 2,525,099</u>	<u>\$ 2,882,240</u>	<u>\$ 2,407,602</u>

Costs incurred in property acquisition, exploration and development activities were:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Property acquisition costs(1):			
Proved properties(2)	\$ 199,966	\$ 302,629	\$ 122,895
Unproved properties(2)	69,801	173,531	48,891
Exploration costs	170,636	231,433	146,450
Development costs	246,669	533,918	398,130
Asset retirement obligation(3)	70,871	259,402	61,861
Capitalized internal costs(4)	35,856	29,465	14,428
Total costs incurred(5)	<u>\$ 793,799</u>	<u>\$ 1,530,378</u>	<u>\$ 792,655</u>

(1) Property acquisition costs include approximately \$6.6 million of hurricane expenditures net of insurance recoveries.

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

- (2) Property acquisition costs attributable to the Company's acquisition of the Edge subsidiaries on December 31, 2009 include \$36.6 million and \$200.8 million for unproved properties and proved properties, respectively.
- (3) Includes asset retirement cost in conjunction with the acquisition of the Edge subsidiaries and operations and the MGOM acquisition of approximately \$5.5 million and \$44.4 million, for the year ended December 31, 2009 and 2008, respectively.
- (4) Costs included capitalized general and administrative expense of \$21.2 million, \$19.8 million and \$14.0 million in 2009, 2008 and 2007, respectively and capitalized interest expense of \$14.7 million, \$9.7 million and \$0.5 million in 2009, 2008 and 2007, respectively.
- (5) Total costs are inclusive of non cash items such as capital expenditures and asset retirement obligation accruals.

The Company capitalizes interest and internal costs associated with exploration and production activities in progress. The capitalized internal costs were approximately 46%, 46%, and 25% of the Company's gross general and administrative expenses, excluding share-based compensation expense for the years ended December 31, 2009, 2008 and 2007, respectively.

The following table summarizes costs related to unevaluated properties that have been excluded from amounts subject to amortization at December 31, 2009. There are no individually significant properties or significant development projects included in the Company's unevaluated property balance. The Company regularly evaluates these costs to determine whether impairment has occurred. The majority of these costs are expected to be evaluated and included in the amortization base within three years.

	Period Incurred Year Ended December 31,				Total at December 31, 2009
	2009	2008	2007	Prior	
	(In thousands)				
Unproved leasehold acquisition and geological and geophysical costs	\$ 46,532	\$ 128,908	\$ 15,618	\$ 23,375	\$ 214,433
Unevaluated exploration and development costs	32,619	22,880	990	148	56,637
Capitalized interest	11,965	8,878	132	192	21,167
Total	<u>\$ 91,116</u>	<u>\$ 160,666</u>	<u>\$ 16,740</u>	<u>\$ 23,715</u>	<u>\$ 292,237</u>

All of the excluded costs at December 31, 2009 relate to activities in the Gulf of Mexico.

Note 16. Supplemental Oil and Gas Reserve and Standardized Measure Information (Unaudited)

Estimated proved net recoverable reserves as shown below for the year ended December 31, 2009 include only those quantities that are expected to be commercially recoverable at the 12-month average price for natural gas and oil calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period to the end of the reporting period and costs in effect at the balance sheet date under existing regulatory practices and with conventional equipment and operating methods. Estimated proved net recoverable reserves as shown below for the years ended December 31, 2008 and 2007 include only those quantities that are expected to be commercially recoverable at prices and costs in effect at the respective balance sheet date under regulatory practices, conventional equipment and operating methods in existence at those dates. Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure is required for recompletion. Also included in the Company's proved undeveloped reserves as of December 31, 2009 were reserves expected to be recovered from wells for which certain drilling and completion operations had

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

occurred as of that date, but for which significant future capital expenditures were required to bring the wells into commercial production.

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

MARINER ENERGY, INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007
ESTIMATED QUANTITIES OF PROVED RESERVES

	Oil & NGLs (Mbbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2006	48,136	426,687	715,503
Revisions of previous estimates	5,690	2,506	36,643
Extensions, discoveries and other additions	4,671	61,548	89,576
Purchases of reserves in place	11,763	25,832	96,407
Sales of reserves in place	(283)	(341)	(2,041)
Production	(5,414)	(67,793)	(100,273)
December 31, 2007	64,563	448,439	835,815
Revisions of previous estimates	(2,404)	(29,839)	(44,264)
Extensions, discoveries and other additions	9,522	137,722	194,855
Purchases of reserves in place	4,102	81,500	106,112
Sales of reserves in place	(40)	(18)	(258)
Production	(6,439)	(79,756)	(118,389)
December 31, 2008	69,304	558,048	973,871
Revisions of previous estimates	3,081	(46,229)	(27,745)
Extensions, discoveries and other additions	14,538	79,474	166,701
Purchases of reserves in place	4,977	70,943	100,803
Sales of reserves in place	—	—	—
Production	(5,950)	(90,801)	(126,498)
December 31, 2009	85,950	571,435	1,087,132

ESTIMATED QUANTITIES OF PROVED DEVELOPED RESERVES

	Oil & NGLs (Mbbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2006	26,807	247,821	408,663
December 31, 2007	39,634	326,069	563,874
December 31, 2008	42,802	420,866	677,679
December 31, 2009	51,587	406,845	716,370

ESTIMATED QUANTITIES OF PROVED UNDEVELOPED RESERVES

	Oil & NGLs (Mbbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (MMcfe)
December 31, 2006	21,329	178,866	306,843
December 31, 2007	24,929	122,370	271,942
December 31, 2008	26,502	137,182	296,191
December 31, 2009	34,363	164,590	370,762

MARINER ENERGY, INC.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
For the Years Ended December 31, 2009, 2008 and 2007

The following is a summary of a Standardized Measure of discounted net future cash flows related to the Company's proved oil and gas reserves. The information presented is based on a calculation of estimated proved reserves using discounted cash flows based on the 12-month average price for natural gas and oil calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period ended December 31, 2009 and year-end prices for the periods ended December 31, 2008 and 2007, year-end costs and economic conditions and a 10% discount rate. The additions to estimated proved reserves from new discoveries and extensions could vary significantly from year to year. Additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, the information presented below should not be viewed as an estimate of the fair value of the Company's oil and gas properties, nor should it be considered indicative of any trends.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Future cash inflows	\$ 6,135,527	\$ 5,609,181	\$ 8,330,819
Future production costs	(2,200,130)	(1,823,535)	(1,970,944)
Future development costs	(1,260,497)	(1,167,113)	(955,278)
Future income taxes	(152,885)	(375,593)	(1,467,999)
Future net cash flows	<u>2,522,015</u>	<u>2,242,940</u>	<u>3,936,598</u>
Discount of future net cash flows at 10% per annum	<u>(1,053,630)</u>	<u>(759,933)</u>	<u>(1,704,689)</u>
Standardized measure of discounted future net cash flows	<u>\$ 1,468,385</u>	<u>\$ 1,483,007</u>	<u>\$ 2,231,909</u>

During recent years, there have been significant fluctuations in the prices paid for crude oil in the world markets and in the United States, including the posted prices paid by purchasers of the Company's crude oil. The Henry Hub 12-month average price of oil and gas at December 31, 2009 used in the table above were \$61.18 per Bbl and \$3.87 per MMBtu. The spot prices of oil and gas at December 31, 2008 and 2007, used in the above table, were \$44.61 and \$96.01 per Bbl, respectively, and \$5.71 and \$6.79 per MMBtu, respectively, and do not include the effect of hedging contracts in place at period end.

MARINER ENERGY, INC.**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**
For the Years Ended December 31, 2009, 2008 and 2007

The following are the principal sources of change in the Standardized Measure of Discounted Future Net Cash Flows (in thousands):

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Standardized Measure — January 1,	\$ 1,483,007	\$ 2,231,909	\$ 1,239,861
Sales and transfers of oil and gas produced, net of production costs	(634,469)	(983,131)	(698,652)
Net changes in prices and production costs	10,984	(1,203,008)	470,932
Extensions and discoveries, net of future development and production costs	206,860	245,718	202,272
Purchases of reserves in place	153,168	157,125	353,441
Development costs during period and net change in development costs	306,834	(89,099)	812,655
Revision of previous quantity estimates	(66,181)	(74,894)	175,039
Sales of reserves in place	—	(1,956)	(1,383)
Net change in income taxes	(150,654)	647,837	(510,611)
Accretion of discount before income taxes	166,747	306,421	123,986
Changes in production rates (timing) and other	(7,911)	246,085	64,369
Standardized Measure — December 31,	\$ 1,468,385	\$ 1,483,007	\$ 2,231,909

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures.

None

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Mariner maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in its filings with the Securities and Exchange Commission (“SEC”) are recorded, processed, summarized and reported within the time period specified in the SEC’s rules and forms, and that such information is accumulated and communicated to management, including its chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosures based on the definition of “disclosure controls and procedures” as defined in Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the “Exchange Act”). In designing and evaluating the disclosure controls and procedures, management has recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance, not absolute assurance, of achieving the desired control objectives, and management is required to apply judgment in evaluating its controls and procedures. As of the end of the period covered by this report, and under the supervision and with the participation of management, including the Company’s Chief Executive Officer and Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of these disclosure controls and procedures. Based on this evaluation, the Company’s Chief Executive Officer and Chief Financial Officer have concluded that the Company’s disclosure controls and procedures were effective as of the end of the period covered by this annual report.

Management’s Report on Internal Control over Financial Reporting

Management’s report on internal control over financial reporting as of December 31, 2009 is in “Item 8. Financial Statements and Supplementary Data” in Part II of this Annual Report on Form 10-K.

Changes in Internal Controls over Financial Reporting.

There were no changes that occurred during the fourth quarter of the fiscal year covered by this Annual Report on Form 10-K that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated by reference to our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K, and with respect to information regarding our executive officers, to “Item 4. Submission of Matters to a Vote of Security Holders — Executive Officers of the Registrant” in this Form 10-K.

Item 11. Executive Compensation.

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) *Financial Statements:*

The financial statements included in Item 8 above are filed as part of this Form 10-K.

(a)(2), (c) *Financial Statement Schedules:*

None.

(a)(3) and (b) *Exhibits:*

The exhibits listed on the Index to Exhibits which follows the Signatures hereto are filed as part of this Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Mariner Energy, Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 1, 2010.

Mariner Energy, Inc.

By: /s/ SCOTT D. JOSEY

Scott D. Josey,
Chairman of the Board, Chief Executive
Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Mariner Energy, Inc. in the capacities indicated as of March 1, 2010:

<u>Signature</u>	<u>Title</u>
<u>/s/ SCOTT D. JOSEY</u> Scott D. Josey	Chairman of the Board, Chief Executive Officer and President (Principal Executive Officer)
<u>/s/ JESUS G. MELENDREZ</u> Jesus G. Melendrez	Senior Vice President, Chief Commercial Officer, Acting Chief Financial Officer and Treasurer (Principal Financial Officer)
<u>/s/ R. CRIS SHERMAN</u> R. Cris Sherman	Vice President and Chief Accounting Officer (Principal Accounting Officer)
<u>/s/ BERNARD ARONSON</u> Bernard Aronson	Director
<u>/s/ ALAN R. CRAIN, JR.</u> Alan R. Crain, Jr.	Director
<u>/s/ JONATHAN GINNS</u> Jonathan Ginns	Director
<u>/s/ JOHN F. GREENE</u> John F. Greene	Director
<u>/s/ H. CLAYTON PETERSON</u> H. Clayton Peterson	Director
<u>/s/ LAURAA. SUGG</u> Laura A. Sugg	Director

INDEX TO EXHIBITS

Number	Description
2.1*	Purchase and Sale Agreement, dated as of December 9, 2009, by and between Edge Petroleum Corporation, Edge Petroleum Exploration Company, Miller Exploration Company, Edge Petroleum Operating Company, Inc., Edge Petroleum Production Company, Miller Oil Corporation, and Mariner Energy, Inc. (incorporated by reference to Exhibit 2.1 to Mariner's Form 8-K filed on January 5, 2010).
2.2*	Membership Interest Purchase Agreement by and between Hydro Gulf of Mexico, Inc. and Mariner Energy, Inc., executed December 23, 2007 (incorporated by reference to Exhibit 2.1 to Mariner's Form 8-K filed on February 5, 2008).
3.1*	Second Amended and Restated Certificate of Incorporation of Mariner Energy, Inc., as amended (incorporated by reference to Exhibit 3.1 to Mariner's Registration Statement on Form S-8 (File No. 333-132800) filed on March 29, 2006).
3.2*	Certificate of Designations of Series A Junior Participating Preferred Stock of Mariner Energy, Inc. (incorporated by reference to Exhibit 3.1 to Mariner's Form 8-K filed on October 14, 2008).
3.3*	Fourth Amended and Restated Bylaws of Mariner Energy, Inc. (incorporated by reference to Exhibit 3.2 to Mariner's Registration Statement on Form S-4 (File No. 333-129096) filed on October 18, 2005).
4.1*	Indenture, dated as of June 10, 2009, among Mariner Energy, Inc., the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on June 16, 2009).
4.2*	First Supplemental Indenture, dated as of June 10, 2009, among Mariner Energy, Inc., the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.2 to Mariner's Form 8-K filed on June 16, 2009).
4.3*	Indenture, dated as of April 30, 2007, among Mariner Energy, Inc., the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on May 1, 2007).
4.4*	Indenture, dated as of April 24, 2006, among Mariner Energy, Inc., the guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on April 25, 2006).
4.5*	Exchange and Registration Rights Agreement, dated as of April 24, 2006, among Mariner Energy, Inc., the guarantors party thereto and the initial purchasers party thereto (incorporated by reference to Exhibit 4.2 to Mariner's Form 8-K filed on April 25, 2006).
4.6*	Rights Agreement, dated as of October 12, 2008, between Mariner Energy, Inc. and Continental Stock Transfer & Trust Company, as Rights Agent (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on October 14, 2008).
4.7*	Amended and Restated Credit Agreement, dated as of March 2, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto from time to time, as Lenders, and Union Bank of California, N.A., as Administrative Agent and as Issuing Lender (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on March 3, 2006).
4.8*	Amendment No. 1 and Consent, dated as of April 7, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on April 13, 2006).
4.9*	Amendment No. 2, dated as of October 13, 2006, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on October 18, 2006).
4.10*	Amendment No. 3 and Consent, dated as of April 23, 2007, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on April 24, 2007).
4.11*	Amendment No. 4, dated as of August 24, 2007, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on August 27, 2007).

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Number	Description
4.12*	Amendment No. 5 and Agreement, dated as of January 31, 2008, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on February 5, 2008).
4.13*	Master Assignment, Agreement and Amendment No. 6, dated as of June 2, 2008, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on June 3, 2008).
4.14*	Amendment No. 7, dated as of December 12, 2008, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on December 15, 2008).
4.15*	Amendment No. 8 and Consent, dated as of March 24, 2009, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on March 27, 2009).
4.16*	Amendment No. 9, dated as of June 2, 2009, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on June 2, 2009).
4.17*	Amendment No. 10, dated as of August 25, 2009, among Mariner Energy, Inc. and Mariner Energy Resources, Inc., as Borrowers, the Lenders party thereto, and Union Bank of California, N.A., as Administrative Agent for such Lenders and as Issuing Lender for such Lenders (incorporated by reference to Exhibit 4.1 to Mariner's Form 8-K filed on August 27, 2009).
10.1*	Underwriting Agreement, dated June 4, 2009, among Credit Suisse Securities (USA) LLC, J.P. Morgan Securities Inc., and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Representatives of the several Underwriters named in Schedule A thereto, and Mariner Energy, Inc. (incorporated by reference to Exhibit 1.1 to Mariner's Form 8-K filed on June 9, 2009).
10.2*	Underwriting Agreement, dated June 4, 2009, among Credit Suisse Securities (USA) LLC, Banc of America Securities LLC, J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC and Citigroup Global Markets Inc., as Representatives of the several Underwriters named in Schedule A thereto, and Mariner Energy, Inc., Mariner Energy Resources, Inc., Mariner Gulf of Mexico LLC, MC Beltway 8 LLC and Mariner LP LLC (incorporated by reference to Exhibit 1.2 to Mariner's Form 8-K filed on June 9, 2009).
10.3*	Underwriting Agreement, dated April 25, 2007, among J.P. Morgan Securities Inc., as Representative of the several Underwriters listed in Schedule 1 thereto, Mariner Energy, Inc., Mariner Energy Resources, Inc., Mariner LP LLC, and Mariner Energy Texas LP (incorporated by reference to Exhibit 1.1 to Mariner's Form 8-K filed on April 26, 2007).
10.4*	Purchase Agreement, dated as of April 19, 2006, among Mariner Energy, Inc., Mariner LP LLC, Mariner Energy Resources, Inc., Mariner Energy Texas LP and the initial purchasers party thereto (incorporated by reference to Exhibit 10.1 to Mariner's Form 8-K filed on April 25, 2006).
10.5*	Form of Indemnification Agreement between Mariner Energy, Inc. and each of its directors and officers (incorporated by reference to Exhibit 10.2 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.6*	Mariner Energy, Inc. Third Amended and Restated Stock Incentive Plan, effective as of May 11, 2009 (incorporated by reference to Exhibit 10.1 to Mariner's Form 8-K filed on May 12, 2009).
10.7*	Form of Non-Qualified Stock Option Agreement, Mariner Energy, Inc. Amended and Restated Stock Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.5 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.8*+	Form of Non-Qualified Stock Option Agreement, Mariner Energy, Inc. Amended and Restated Stock Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.6 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).

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Number	Description
10.9*+	Form of Restricted Stock Agreement (directors) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Mariner's Form 10-K filed on April 2, 2007).
10.10*+	Form of Restricted Stock Agreement (employee with employment agreement) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.7 to Mariner's Form 10-K filed on April 2, 2007).
10.11*	Form of Restricted Stock Agreement (employee without employment agreement) under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.8 to Mariner's Form 10-K filed on April 2, 2007).
10.12*+	Form of Restricted Stock Agreement for grants made after August 24, 2008 as part of 2008 Long-Term Performance-Based Restricted Stock Program under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to Mariner's Form 10-Q filed on November 7, 2008).
10.13*+	Form of Restricted Stock Agreement for grants made before August 25, 2008 as part of 2008 Long-Term Performance-Based Restricted Stock Program under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Mariner's Form 8-K filed on June 19, 2008).
10.14*+	Amendment, dated as of August 25, 2008, to outstanding Restricted Stock Agreements covering grants made before August 25, 2008 as part of 2008 Long-Term Performance-Based Restricted Stock Program under Mariner Energy, Inc. Second Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.5 to Mariner's Form 10-Q filed on November 7, 2008).
10.15*	Form of Nonstatutory Stock Option Agreement for certain employees of Mariner Energy, Inc. or Mariner Energy Resources, Inc. who formerly held unvested options issued by Forest Oil Corporation (incorporated by reference to Exhibit 10.14 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.16*+	Compensation of Non-Employee Directors of Mariner Energy, Inc. (incorporated by reference to Exhibit 10.3 to Mariner's Form 10-Q filed on November 14, 2007).
10.17*+	Employment Agreement by and between Mariner Energy, Inc. and Scott D. Josey, dated February 7, 2005 (incorporated by reference to Exhibit 10.15 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.18*+	Employment Agreement by and between Mariner Energy, Inc. and Dalton F. Polasek, dated February 7, 2005 (incorporated by reference to Exhibit 10.16 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.19*+	Employment Agreement, by and between Mariner Energy, Inc. and John H. Karnes, dated as of October 16, 2006 (incorporated by reference to Exhibit 10.1 to Mariner's current report on Form 8-K filed on October 18, 2006).
10.20*+	Employment Agreement by and between Mariner Energy, Inc. and Michiel C. van den Bold, dated February 7, 2005 (incorporated by reference to Exhibit 10.17 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.21*+	Amendment to Employment Agreement by and between Mariner Energy, Inc. and Michiel C. van den Bold, dated as of June 8, 2006 (incorporated by reference to Exhibit 10.18 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.22*+	Second Amended and Restated Employment Agreement by and between Mariner Energy, Inc., Mariner Energy Resources, Inc. and Judd Hansen, dated June 8, 2006 (incorporated by reference to Exhibit 10.19 to Mariner's Registration Statement on Form S-4 (File No. 333-137441) filed on September 19, 2006).
10.23+	Employment Agreement by and between Mariner Energy, Inc. and Jesus Melendrez, dated as of February 7, 2005.
10.24+	Amendment to Employment Agreement by and between Mariner Energy, Inc. and Jesus Melendrez, dated as of June 8, 2006.
12	Statement regarding Computation of Ratio of Earnings to Fixed Charges.
21	List of subsidiaries of Mariner Energy, Inc.
23.1	Consent of Deloitte & Touche LLP.
23.2	Consent of Ryder Scott Company, L.P.

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Number	Description
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of Ryder Scott Company, L.P. dated February 1, 2010.

* Incorporated by reference as indicated.

+ Management contract, plan or arrangement.

In accordance with SEC Release 33-8238, Exhibits 32.1 and 32.2 are being furnished and not filed.

EMPLOYMENT AGREEMENT

This Employment Agreement (“**Agreement**”) is made and entered into as of February 7, 2005 (the “**Effective Date**”), by and between **Mariner Energy, Inc.**, a Delaware corporation (hereafter “**Company**”), and **Jesus Melendrez** (hereafter “**Executive**”).

1. Employment. During the Employment Period (as defined in Section 4 hereof), the Company shall employ Executive, and Executive shall serve, as Vice President.

2. Duties and Responsibilities of Executive.

(a) During the Employment Period, Executive shall devote his full time and attention during normal business hours to the business of the Company, will act in the best interests of the Company and will perform with due care his duties and responsibilities. Executive’s duties will include those normally incidental to the position of Vice President as well as whatever additional duties may be assigned to him by the Board of Directors of the Company (the “**Board**”) or the Chief Executive Officer of the Company. Executive agrees to cooperate fully with the Board and the Chief Executive Officer of the Company and not to engage in any activity that materially interferes with the performance of Executive’s duties hereunder. During the Employment Period, Executive will not hold outside employment without the advance written approval of the Board. *Provided that* it shall not be a violation of this Agreement for Executive to (1) serve on corporate, civic, or charitable boards or committees (except for boards or committees of a business organization that competes with the Company in any business in which the Company is regularly engaged), which are listed on **Exhibit A** so long as such service does not materially interfere with the performance of Executive’s duties and responsibilities under this Agreement, as determined in the good faith opinion of the Board, (2) manage personal investments, or (3) take vacation days and reasonable absences due to injury or illness, as set forth herein and/or permitted by the general policies of the Company.

(b) Executive represents and covenants to the Company that he is not subject or a party to any employment agreement, noncompetition covenant, nondisclosure agreement, or any other agreement, covenant, understanding, or restriction that would prohibit Executive from executing this Agreement and fully performing his duties and responsibilities hereunder, or would in any manner, directly or indirectly, limit or affect the duties and responsibilities that may now or in the future be assigned to Executive hereunder.

(c) Executive acknowledges and agrees that Executive owes the Company a duty of loyalty and that the obligations described in this Agreement are in addition to, and not in lieu of, the obligations Executive owes the Company under the common law.

3. Compensation.

(a) During the Employment Period (as defined in Section 4 hereof), the Company shall pay to Executive an annualized base salary of \$187,500 (the “**Base Salary**”) in consideration for Executive’s services under this Agreement, payable on a not less than semi-monthly basis, in conformity with the Company’s customary payroll practices for executive salaries. For all purposes of this Agreement, Executive’s Base Salary shall include any portion thereof which is deferred under any nonqualified plan or arrangement. Each year, the Board shall review Executive’s salary based on market survey data, corporate performance, and performance of Executive. If, in its sole and complete discretion, the Board determines that an increase in Executive’s salary is appropriate, the Board may make such adjustment, and such adjusted salary shall thereafter be Executive’s Base Salary for purposes of this Agreement. Executive’s Base Salary may not be reduced except as part of a general reduction of salaries paid to management employees that is necessitated by business conditions, as determined by the Board.

(b) Executive may be eligible for an annual discretionary performance bonus with respect to each calendar year during the Employment Period (the “**Annual Bonus**”). The amount, if any, of Executive’s Annual Bonus will be determined by the Board in its sole and complete discretion based on market survey data, corporate performance, and performance of Executive. Bonus determinations will be made by the Board at a time convenient to the Board but typically within 60 calendar days of the end of each calendar year. The Board will, on an annual basis (at or near the beginning of each calendar year in the Employment Period) establish a target bonus for Executive for the upcoming year, and will communicate such target to Executive. If the Board determines to award Executive an Annual Bonus, it will be payable in conformity with the Company’s customary payroll practices for executive bonuses. The Board may also award additional bonuses or other compensation to Executive at any time in its sole and complete discretion.

(c) Any salary, bonus, and other compensation payments hereunder shall be subject to such payroll and other taxes, withholdings, and deductions as may be required by applicable law or with respect to Executive’s coverage in the Company’s insurance and other employee benefit plans.

4. Term of Employment. The initial term of this Agreement shall be for the period beginning on the Effective Date and ending at midnight (EST) on March 2, 2006 (the “**Initial Term**”); *provided, however*, that if the Company consummates an initial public offering of its common stock prior to March 3, 2006, the Initial Term shall end on March 2, 2007. For all purposes of this Agreement, the consummation of a sale under Rule 144A and/or Regulation D of equity securities of the Company shall be treated as the consummation of an initial public offering by the Company. On March 3, 2006 (or 2007, if applicable) and on March 3 of each succeeding year (each such date being referred to as a “**Renewal Date**”), this Agreement shall automatically renew and extend for a period of 12 months (a “**Renewal Term**”) unless written notice of non-renewal is delivered from one party to the other at least 90 days prior to such

Renewal Date (in which case the Termination Date shall be the day immediately prior to such Renewal Date). Notwithstanding any other provision of this Agreement, this Agreement may be terminated at any time during the Initial Term or the Renewal Term (if any) in accordance with Section 6. The period from the Effective Date through the Termination Date of this Agreement, regardless of the time or reason for such termination, shall be referred to herein as the “**Employment Period**.” In the event that this Agreement is not renewed, Executive shall become an at-will employee of the Company and the Company shall have the right to terminate Executive’s employment with the Company at any time.

5. Benefits. Subject to the terms and conditions of this Agreement, Executive shall be entitled to the following benefits during the Employment Period:

(a) **Reimbursement of Business Expenses.** The Company agrees to reimburse Executive for reasonable business-related expenses incurred in the performance of Executive’s duties under this Agreement.

(b) **Benefit Plans and Programs.** To the extent permitted by applicable law and subject to the terms and eligibility requirements of any such plan or program, Executive will be eligible to participate in all benefit plans and programs, including improvements or modifications of the same, that are maintained by the Company generally for executive employees of the Company, subject to the eligibility requirements and other terms and conditions of those plans and programs. The Company will not, however, by reason of this Section 5(b) be obligated either (1) to institute, maintain, or refrain from changing, amending, or discontinuing any such benefit plan or program, or (2) to provide Executive with all benefits provided to any other person or individual employed by the Company or any of its affiliates.

6. Termination of Employment.

(a) **Company’s Right to Terminate.** At any time during the Initial Term or any Renewal Term, the Company shall have the right to terminate this Agreement and Executive’s employment with the Company for any of the following reasons:

- (1) Upon Executive’s death (in which case the Termination Date shall be the date of Executive’s death);
- (2) Upon Executive’s Disability (as defined below);
- (3) For Cause (as defined in Section 7); or
- (4) For any other reason whatsoever, in the sole and complete discretion of the Company.

(b) **Executive’s Right to Terminate.** At any time during the Initial Term or any Renewal Term, Executive will have the right to terminate this Agreement and Executive’s employment with the Company for:

(1) Good Reason (as defined in Section 7); or

(2) For any other reason whatsoever, in the sole and complete discretion of Executive.

(c) **“Disability.”** For purposes of this Agreement, “Disability” means that Executive has sustained sickness or injury that renders Executive incapable of performing the duties and services required of Executive hereunder for a period of 90 consecutive calendar days or a total of 120 calendar days during any 12 month period.

(d) **“Notices.”** Any termination of this Agreement by the Company under Section 6(a) (other than termination due to the death of Executive), or by Executive under Section 6(b) shall be communicated by a Notice of Termination to the other party. A “Notice of Termination” means a written notice that (1) indicates the specific termination provision in this Agreement relied upon and (2) if the termination is by the Company for Cause or by Executive for Good Reason, sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of Executive’s employment under the provision so indicated. The Notice of Termination must specify the Termination Date. In the case of a termination by the Company for Cause or due to Executive’s Disability, or by Executive for Good Reason, the Termination Date may be as early as the date notice is given but no later than 30 calendar days after notice is given, unless otherwise agreed to in writing by both parties. In the case of a termination by the Company or by Executive for any other reason, the Termination Date may be as early as 14 calendar days after notice is given but no later than 60 calendar days after notice is given, unless otherwise agreed to by the parties in writing.

7. Severance Payments.

(a) **Termination by the Company.** If (1) the Company terminates this Agreement and Executive’s employment with the Company and its affiliates during the Initial Term or the Renewal Term (if any) pursuant to Section 6(a)(4), (2) Executive signs and does not revoke a waiver and release agreement substantially similar to Exhibit B, and (3) Executive continues to comply with Executive’s ongoing obligations under Sections 11 and 12 of this Agreement, then, subject to Section 7(h), the Company shall pay Executive severance in accordance with Section 7(c). Such severance payments shall be in addition to payment by the Company of all previously unpaid amounts (including, without limitation, salary, bonuses, equity plans, incentive compensation plans, fringe benefits, and expense reimbursements) owed to Executive under this Agreement with respect to periods prior to the Termination Date.

(b) **Termination by Executive.** If (1) Executive terminates this Agreement and Executive’s employment with the Company and its affiliates during the Initial

Term or the Renewal Term (if any) pursuant to Section 6(b)(1), (2) Executive signs and does not revoke a waiver and release agreement substantially similar to Exhibit B, and (3) Executive continues to comply with Executive's ongoing obligations under Sections 11 and 12 of this Agreement, then, subject to Section 7(h), the Company shall pay Executive severance in accordance with Section 7(c). Such severance payments shall be in addition to payment by the Company of all previously unpaid amounts (including, without limitation, salary, bonuses, equity plans, incentive compensation plans, fringe benefits, and expense reimbursements) owed to Executive under this Agreement with respect to periods prior to the Termination Date.

(c) **Severance Amount.** If the Company is required to pay Executive severance by the express terms of Section 7(a) or 7(b), the Company shall pay Executive the following as severance:

(1) Executive's Base Salary at the highest rate in effect prior to the Termination Date as salary continuation for a period of eighteen months commencing on the date on which Executive's employment with the Company is terminated (the "**Termination Date**") (the "**Severance Period**"), payable in equal monthly installments pursuant to the Company's customary payroll practices for executive salaries; *provided, however*, that, at the option of the Company, the amounts payable under this Section 7(c) may be paid by the Company in one lump sum.

(2) Executive, Executive's spouse, and Executive's dependents will continue to be eligible for coverage under the Company's group health plan or any successor plan on the same basis as active executive employees of the Company, their spouses, and their dependents for the duration of the Severance Period. If and when group health coverage under another employer's plan is made available to Executive, Executive's spouse, or Executive's dependents, the Company's obligations under this paragraph will cease with respect to each person to whom such coverage is made available, notwithstanding that such person may not in fact become covered under such other employer's plan. Executive's portion of the premium for such coverage shall be withheld from the salary continuation payments described in paragraph (1) immediately above or, if salary continuation has been paid in a lump sum, Executive shall reimburse the Company for Executive's portion of the premium on a monthly basis.

(3) An amount equal to the sum of amounts paid or payable to Executive as bonuses by the Company for the year prior to the year in which the Termination Date occurs. This amount will be payable in one lump sum, to Executive within 30 days after the end of the Severance Period.

(4) Executive shall become 100% vested in all of the shares of restricted stock granted to Executive under the Mariner Energy, Inc. Equity

Participation Plan to the extent Executive is less than 100% vested in such shares as of the Termination Date.

(5) Executive shall become 50% vested in all of the rights and interests granted to Executive under the Company's stock and other equity plans (other than the Mariner Energy, Inc. Equity Participation Plan), including without limitation any stock options, restricted stock, restricted stock units, performance units, and/or performance shares to the extent Executive is less than 50% vested in such award as of the Termination Date.

(6) Notwithstanding any other provision hereof, if the Company incurs an obligation to pay severance under this Section 7(c) in connection with the termination of Executive's employment after the consummation of an initial public offering by the Company, then, subject to Section 7(h), Executive shall be entitled to receive the amounts specified in Section 8(a) in lieu of the amounts specified in Sections 7(c)(1) and 7(c)(3).

(7) Payments under this Section 7(c) shall be in lieu of any severance benefits otherwise due to Executive under any severance pay plan or program maintained by the Company that covers its employees or executives generally. If Executive receives payment under Section 8(a), payments otherwise payable under Section 7(c)(1) shall terminate.

(d) Termination in Event of Executive's Disability. If (1) the Company terminates Executive's employment with the Company and its affiliates during the Initial Term or the Renewal Term (if any) pursuant to Section 6(a)(2), (2) Executive signs and does not revoke a waiver and release agreement substantially similar to Exhibit B, and (3) Executive continues to comply with Executive's ongoing obligations under Section 11 and 12 of this Agreement, then, subject to Section 7(h), the Company shall pay Executive the severance described in accordance with Section 7(e). Such severance payments shall be in addition to payment by the Company of all previously unpaid amounts (including, without limitation, salary, bonuses, equity plans, incentive compensation plans, fringe benefits, and expense reimbursements) owed to Executive under this Agreement with respect to periods prior to the Termination Date.

(e) Disability Severance. If the Company is required to pay Executive severance by the express terms of Section 7(d), the Company shall pay Executive the following as severance:

(1) Executive's Base Salary at the highest rate in effect prior to the Termination Date as salary continuation for the duration of the Severance Period, payable in equal monthly installments pursuant to the Company's customary payroll practices for executive salaries; *provided, however*, that, at the option of the Company, the amounts payable under this Section 7(e) may be paid by the Company in one lump sum.

- (2) Executive, Executive's spouse, and Executive's dependents will continue to be eligible for coverage under the Company's group health plan or any successor plan on the same basis as active executive employees of the Company, their spouses, and their dependents for the duration of the Severance Period. Executive's portion of the premium for such coverage shall be withheld from the salary continuation payments described in paragraph (1) immediately above or, if salary continuation has been paid in a lump sum, Executive shall reimburse the Company for Executive's portion of the premium on a monthly basis. If and when group health coverage under another employer's plan is made available to Executive, Executive's spouse, or Executive's dependents, the Company's obligations under this paragraph will cease with respect to each person to whom such coverage is made available, notwithstanding that such person may not in fact become covered under such other employer's plan.
- (3) An amount equal to the sum of amounts paid or payable to Executive as bonuses awarded by the Company for the calendar year prior to the calendar year in which the Termination Date occurs. This amount will be payable in one lump sum to Executive within 30 days after the end of the Severance Period.
- (4) Executive shall become 100% vested in all of the shares of restricted stock granted to Executive under the Mariner Energy, Inc. Equity Participation Plan to the extent Executive is less than 100% vested in such shares as of the Termination Date.
- (5) Executive shall become 50% vested in all of the rights and interests granted to Executive under the Company's stock and other equity plans (other than the Mariner Energy, Inc. Equity Participation Plan), including without limitation any stock options, restricted stock, restricted stock units, performance units, and/or performance shares to the extent Executive is less than 50% vested in such award as of the Termination Date.
- (6) Notwithstanding any other provision hereof, if the Company incurs an obligation to pay severance under this Section 7(e) in connection with termination of Executive's employment after the consummation of an initial public offering by the Company, then, subject to Section 7(h), Executive shall be entitled to receive the amounts specified in Section 8(a) in lieu of the amounts specified in Sections 7(e)(1) and 7(e)(3).
- (7) Payments under this Section 7(e) shall be in lieu of any severance benefits otherwise due to Executive under any severance pay plan or program maintained by the Company that covers its employees or executives generally.
- (f) "**Cause**" means the occurrence or existence, prior to occurrence of circumstances constituting Good Reason, of any of the following events:

- (1) Executive's gross negligence or material mismanagement in performing, or material failure or inability (excluding as a result of death or Disability) to perform, Executive's duties and responsibilities as described herein or as lawfully directed by the Board or the Chief Executive Officer of the Company;
- (2) Executive's having committed any act of willful misconduct or material dishonesty against the Company or any of its affiliates (including theft, misappropriation, embezzlement, forgery, fraud, falsification of records, or misrepresentation) or any act that results in, or could reasonably be expected to result in, material injury to the reputation, business or business relationships of the Company or any of its affiliates;
- (3) Executive's material breach of this Agreement, any fiduciary duty owed by Executive to the Company or its affiliates, or any written workplace policies applicable to Executive (including the Company's code of conduct and policy on workplace harassment) whether adopted on or after the date of this Agreement;
- (4) Executive's having been convicted of, or having entered a plea bargain, a plea of *nolo contendere* or settlement admitting guilt for, any felony, any crime of moral turpitude, or any other crime that could reasonably be expected to have a material adverse impact on the Company's or any of its affiliates' reputations; or
- (5) Executive's having committed any material violation of any federal law regulating securities (without having relied on the advice of the Company's attorney to perform required acts on the Chief Executive Officer's behalf) or having been the subject of any final order, judicial or administrative, obtained or issued by the Securities and Exchange Commission, for any securities violation involving fraud, including, for example, any such order consented to by Executive in which findings of facts or any legal conclusions establishing liability are neither admitted nor denied.
- (g) "**Good Reason**" means the occurrence, prior to occurrence of circumstances constituting Cause, of any of the following events without Executive's consent:
- (1) Any material breach by the Company of this Agreement, *provided* that Executive provides the Board written notice of such breach within 90 days from the first date that he is aware, or reasonably should be aware, of such breach and such breach is not remedied within 30 days of the Board's receipt of such written notice;

- (2) Any requirement by the Company that Executive relocate outside of the Houston metropolitan area;
- (3) Failure of any successor to assume this Agreement not later than the date as of which it acquires substantially all of the equity, assets or businesses of the Company;
- (4) Any material reduction in Executive's title, responsibilities, or duties; or
- (5) The assignment to Executive of any duties materially inconsistent with his duties as Vice President of the Company.

(h) **Later Determinations.** Notwithstanding any other provision of this Agreement, if Executive's employment with the Company is terminated such that Executive is entitled to severance from the Company and within one year following such termination the Board determines that Cause exists or existed on, prior to, or after such termination, Executive shall not be entitled to any severance from the Company, and any and all severance payments from the Company to Executive in any form or amount shall cease and any such payments or reimbursements already made to Executive must be returned to the Company.

8. Change of Control.

(a) Upon the termination of Executive's employment with the Company for any reason other than Cause at any time on or within nine months after a Change of Control that occurs during the Employment Period or upon the occurrence of a Change of Control within nine months following a termination of Executive's employment that entitles Executive to severance under Section 7(c), the Company shall pay Executive, subject to Section 8(d) below, an amount equal to 2.0 times the sum of Executive's Base Salary plus his Average Bonus Amount. The Executive's "Average Bonus Amount" shall be the average annual amount paid or payable to Executive as bonuses for the Company's three calendar years ended immediately prior to the occurrence of the Change of Control (or for the number of calendar years that Executive has been an employee of the Company before the occurrence of the Change of Control, if less than three); provided that any payment otherwise payable under this Section 8(a) shall be subject to Section 7(h) notwithstanding that such payment is not a severance payment.

(b) Upon the occurrence of a Change of Control that occurs during the Employment Period or within nine months following a termination of Executive's employment that entitles Executive to severance under Section 7(c), Executive shall become 100% vested in all of the rights and interests granted to Executive under the Company's stock and other equity plans, including without limitation any stock options, restricted stock, restricted stock units, performance units, and/or performance shares to the extent Executive is less than 100% vested in such award as of the Termination Date.

(c) "Change of Control" means (i) after the Effective Date, any person or group of affiliated or associated persons acquires more than 35% of the voting power of the Company; (ii)

the consummation of a sale of all or substantially all of the assets of the Company; (iii) the dissolution of the Company or (iv) the consummation of any merger, consolidation, or reorganization involving the Company in which, immediately after giving effect to such merger, consolidation or reorganization, less than 51% of the total voting power of outstanding stock of the surviving or resulting entity is then “beneficially owned” (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934, as amended) in the aggregate by the stockholders of the Company immediately prior to such merger, consolidation or reorganization. Notwithstanding the foregoing, a Change of Control shall not include any acquisitions resulting from the consummation of the private placement offering of common stock of the Company under Rule 144A and/or Regulation D prior to March 31, 2005.

(d) Except as provided below, such Change of Control payments shall be in addition to payment by the Company of all other amounts (including, without limitation, salary, bonuses, equity plans, incentive compensation plans, fringe benefits, and expense reimbursements) owed to Executive under other provisions of this Agreement. Notwithstanding the foregoing, if on or before the Change of Control Executive becomes or has become entitled to payment pursuant to Section 7(c), the amount payable under this Section 8 shall be reduced by the amount paid or payable to Executive under Section 7(c).

9. Gross-up Parachute Payment. In the event that Executive shall become entitled to any amounts (the “Regular Amounts”), whether pursuant to the terms of this Agreement or any other plan, arrangement or agreement with the Company, any person whose actions result in a change of ownership covered by Section 280G(b)(2) of the Internal Revenue Code of 1986, as amended, or any person affiliated with the Company or such person, that will be subject to the tax (the “Excise Tax”) imposed by Section 4999 of the Code (and any similar tax that may hereafter be imposed), the Company shall pay to Executive an additional amount (the “Gross-up Payment”) such that the net amount retained by Executive after payment of all applicable federal and state taxes on the sum of the Regular Amount plus the Gross-up Payment, is equal to the net amount that would have been retained by Executive after payment of all applicable federal and state taxes on the Regular Amount if it had not been subject to the Excise Tax.

10. Conflicts of Interest. Executive agrees that he shall promptly disclose to the Board any conflict of interest involving Executive upon Executive becoming aware of such conflict. Executive’s ownership of an interest not in excess of five percent in a business organization that competes with the Company shall not be deemed to constitute a conflict of interest.

11. Confidentiality. The Company agrees to provide Executive valuable Confidential Information of the Company and of third parties who have supplied such information to the Company. In consideration of such Confidential Information and other valuable consideration provided hereunder, Executive agrees to comply with this Section 11.

(a) “**Confidential Information**” means, without limitation and regardless of whether such information or materials are expressly identified as confidential or proprietary, (i) any and all non-public, confidential or proprietary information or work product of the Company or its affiliates, (ii) any information that gives the

Company or its affiliates a competitive business advantage or the opportunity of obtaining such advantage, (iii) any information the disclosure or improper use of which is reasonably expected to be detrimental to the interests of the Company or its affiliates, (iv) any trade secrets of the Company or its affiliates, and (v) any other information of or regarding the Company or any of its affiliates, or its or their past, present or future, direct or indirect, potential or actual officers, directors, employees, owners, or business partners, including but not limited to information regarding any of their businesses, operations, assets (including any Oil and Gas Interests as defined below), liabilities, properties, systems, methods, models, processes, results, performance, investments, investors, financial affairs, future plans, business prospects, acquisition or investment opportunities, strategies, business partners, business relationships, contracts, contractual relationships, organizational or personnel matters, policies or procedures, management or compensation matters, compliance or regulatory matters, as well as any technical, seismic, industry, market or other data, studies or research, or any forecasts, projections, valuations, derivations or other analyses, performed, generated, collected, gathered, synthesized, purchased or owned by, or otherwise in the possession of, the Company or its affiliates or which Executive has learned of through his employment with the Company. Confidential Information also includes any non-public, confidential or proprietary information about or belonging to any third party which has been entrusted to the Company or its affiliates. Notwithstanding the foregoing, Confidential Information does not include any information which is or becomes generally known by the public other than as a result of Executive's actions or inactions. **"Oil and Gas Interests"** means: (a) direct and indirect interests in and rights with respect to oil, gas, mineral and related properties (including revenues or net revenues therefrom) and assets of any kind and nature, direct or indirect, including without limitation working, royalty and overriding royalty interests, mineral interests, leasehold interests, production payments, operating rights, net profits interests, other non-working interests and non-operating interests; (b) interests in and rights with respect to Hydrocarbons and other minerals or revenues therefrom and contracts or agreements in connection therewith and claims and rights thereto (including oil and gas leases, operating agreements, unitization and pooling agreements and orders, division orders, transfer orders, mineral deeds, royalty deeds, oil and gas sales, exchange and processing contracts and agreements and, in each case, interests thereunder), surface interests, fee interests, reversionary interests, reservations and concessions; (c) easements, rights of way, licenses, permits, leases, and other interests associated with, appurtenant to, or necessary for the operation of any of the foregoing; and (d) interests in equipment and machinery (including well equipment and machinery), oil and gas production, gathering, transmission, compression, treating, processing and storage facilities (including tanks, tank batteries, pipelines and gathering systems), pumps, water plants, electric plants, gasoline and gas processing plants, refineries and other tangible personal property and fixtures associated with, appurtenant to, or necessary for the operation of any of the foregoing, regardless of location. **"Hydrocarbons"**

means oil, condensate gas, casinghead gas and other liquid or gaseous hydrocarbons.

(b) **Protection.** In return for the Company's promise to provide Executive with Confidential Information, Executive promises (i) to keep the Confidential Information, and all documentation, materials and information relating thereto, strictly confidential, (ii) not to use the Confidential Information for any purpose other than as required in connection with fulfilling his duties as Vice President for the benefit of the Company, and (iii) to return to the Company all documents containing Confidential Information in Executive's possession upon separation from the Company for any reason. For the sake of clarity, Executive specifically acknowledges and agrees that (x) the definition of Confidential Information in Section 11(a) includes (but is not limited to) any nonpublic information about the Oil and Gas Interests (as defined above) and any other assets, investments, properties, sites or locations in which the Company or its affiliates have an ownership or other interest or right, as well as any Oil and Gas Interests (as defined above), assets, investments, properties, sites, locations, acquisitions or other business prospects upon which the Company or its affiliates have expended resources in the past, are currently expending resources, or are contemplating expending resources in the future, and (y) that any use by Executive of such Confidential Information other than as required in connection with fulfilling his duties as Executive for the benefit of the Company will be a material breach of this Agreement. The immediately preceding sentence has been included for the purpose of highlighting certain aspects of the foregoing covenants and shall in no event be read to limit or narrow the foregoing covenants.

(c) **Scope.** Executive understands and agrees that all Confidential Information, in whatever medium (verbal, written, electronic or other), is subject to this Agreement whether provided directly to Executive or not, whether provided to Executive prior to the Effective Date of this Agreement or not, and whether inadvertently disclosed to Executive or not. Confidential Information which was or is available to Executive or to which Executive had or has access will be deemed to have been provided to Executive. Executive also hereby agrees that Confidential Information shall be deemed to include information regarding the assets of the Company, even if such information was learned by Executive prior to formation of the Company.

(d) **Value and Security.** Executive understands and agrees that all Confidential Information, and every portion thereof, constitutes the valuable intellectual property of the Company, its affiliates, and/or third parties, and Executive further acknowledges the importance of maintaining the security and confidentiality of the Confidential Information and of not misusing the Confidential Information.

(e) **Disclosure Required By Law.** If Executive is legally required to disclose any Confidential Information, Executive shall promptly notify the Company in

writing of such request or requirement so that the Company may seek an appropriate protective order or other relief. Executive agrees to cooperate with and not to oppose any effort by the Company to resist or narrow such request or to seek a protective order or other appropriate remedy. In any case, Executive will (a) disclose only that portion of the Confidential Information that, according to the advice of Executive's counsel, is required to be disclosed (and Executive's disclosure of Confidential Information to Executive's counsel in connection with obtaining such advice shall not be a violation of this Agreement), (b) use reasonable efforts (at the expense of the Company) to obtain assurances that such Confidential Information will be treated confidentially, and (c) promptly notify the Company in writing of the items of Confidential Information so disclosed.

(f) **Third-Party Confidentiality Agreements.** To the extent that the Company possesses any Confidential Information which is subject to any confidentiality agreements with, or obligations to, third parties, Executive will comply with all such agreements or obligations in full. The immediately preceding sentence shall apply only if the Company has provided Executive with a copy of such agreements, and Executive may disclose such agreements and any related Confidential Information to Company's attorneys and rely on their advice regarding compliance therewith.

(g) **Survival.** The covenants made by Executive in this Section 11, other than Paragraph (f) hereof, will be effective only during the Employment Period and for the two-year period immediately following the Employment Period, and to that extent (and only that extent) shall survive termination of this Agreement. The covenants made by Executive in Paragraph (f) of this Section 11 will be effective during the period specified in the confidentiality agreements described therein.

12. No Solicitation. Executive shall not, for a period of one year after the Termination Date, either as principal, agent, independent contractor, consultant, director, officer, employee, employer, advisor, stockholder, partner, member, joint venturer, owner or in any other individual or representative capacity whatsoever, whether paid or unpaid, either for his own benefit or for the benefit of any other person or entity, either (A) contact or solicit, with respect to hiring, any person known by Executive to be or to have been, at any time during the 12-month period immediately preceding the Termination Date, an employee of the Company or its affiliates, or (B) induce or otherwise counsel, advise or encourage any employee of the Company or its affiliates to leave the employment of the Company or their respective employment with the Company's affiliates, as the case may be; provided, however, that this restriction shall not apply to any solicitations contained in an advertisement directed generally to the public or the trade, nor to any contacts resulting from such a solicitation. If Executive fails to comply with this Section 12, the Company shall be entitled to, among other remedies, compliance by Executive with the terms of this section for an additional period of time that shall equal the period over which such noncompliance occurred. Notwithstanding any other provision hereof, this Section 12 shall not apply (1) if the Company terminates Executive's employment with the Company and its affiliates pursuant to Section 6(a)(4) or pursuant to delivery by the Company to Executive of a

notice of non-renewal in accordance with Section 4, (2) if Executive terminates Executive's employment with the Company and its affiliates pursuant to Section 6(b)(1), or (3) after the occurrence of a Change of Control.

13. Defense of Claims. Executive agrees that, during the Employment Period and for a period of 36 months after the Termination Date, upon request from the Company, Executive will cooperate with the Company and its affiliates in the defense of any claims or actions that may be made by or against the Company or any of its affiliates that relate to Executive's prior areas of responsibility, except if Executive's reasonable interests are adverse to the Company or affiliates in such claim or action. If Executive is not an employee of the Company or an affiliate at such time, the Company agrees to compensate Executive for his time spent on such matters at the rate of \$150 per hour, and in addition, to pay or reimburse Executive for all of Executive's reasonable travel and other direct expenses incurred, or to be reasonably incurred, to comply with Executive's obligations under this Section 13, provided Executive provides reasonable documentation of same.

14. Withholdings: Right of Offset. The Company may withhold and deduct from any payments made or to be made pursuant to this Agreement (a) all federal, state, local and other taxes as may be required pursuant to any law or governmental regulation or ruling, (b) any deductions consented to in writing by Executive, and (c) any other sums owed by Executive to the Company, any affiliate, or any employee benefit plan or program of the Company or any affiliate.

15. Severability. It is the desire of the parties hereto that this Agreement be enforced to the maximum extent permitted by law, and should any provision contained herein be held unenforceable by a court of competent jurisdiction or arbitrator (pursuant to Section 17), the parties hereby agree and consent that such provision shall be reformed to create a valid and enforceable provision to the maximum extent permitted by law; *provided, however*, if such provision cannot be reformed, it shall be deemed ineffective and deleted herefrom without affecting any other provision of this Agreement.

16. Title and Headings: Construction. Titles and headings to Sections hereof are for the purpose of reference only and shall in no way limit, define or otherwise affect the provisions hereof. Any and all Exhibits referred to in this Agreement are, by such reference, incorporated herein and made a part hereof for all purposes. The words "herein", "hereof", "hereunder" and other compounds of the word "here" shall refer to the entire Agreement and not to any particular provision hereof.

17. Arbitration; Injunctive Relief; Attorneys' Fees.

(a) Subject to Section 17(b), any dispute, controversy or claim between Executive and the Company arising out of or relating to this Agreement, Executive's employment with Company, or the termination of either will be finally settled by arbitration in Houston, Texas before, and in accordance with the rules for the resolution of employment disputes then obtaining of, the American Arbitration Association. The arbitrator's award shall be final and binding on both parties.

(b) Notwithstanding Section 17(a), an application for emergency or temporary injunctive relief by either party shall not be subject to arbitration under this Section 17; provided, however, that the remainder of any such dispute (beyond the application for emergency or temporary injunctive relief) shall be subject to arbitration under this Section 17. Executive acknowledges that Executive's violation of Sections 11 and/or 12 of this Agreement will cause irreparable harm to the Company, Executive agrees not to contest that Executive's violation of Sections 11 and/or 12 of this Agreement will cause irreparable harm to the Company and Executive agrees that the Company shall be entitled as a matter of right to specific performance of Executive's obligations under Sections 11 and 12 and an injunction, from any court of competent jurisdiction, restraining any violation or further violation of such agreements by Executive or others acting on his/her behalf, without any showing of irreparable harm and without any showing that the Company does not have an adequate remedy at law. The Company's right to injunctive relief shall be cumulative and in addition to any other remedies provided by law or equity.

(c) Each side shall share equally the cost of the arbitrator and bear its own costs and attorneys' fees incurred in connection with any arbitration, unless a statutory claim authorizing the award of attorneys' fees is at issue, in which event the arbitrator may award a reasonable attorneys' fee in accordance with the jurisprudence of that statute.

(d) Nothing in this Section 17 shall prohibit a party to this Agreement from (i) instituting litigation to enforce any arbitration award or (ii) joining another party to this Agreement in a litigation initiated by a person which is not a party to this Agreement.

18. Governing Law. THIS AGREEMENT WILL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, WITHOUT REFERENCE TO PRINCIPLES OF CONFLICT OF LAWS. THE EXCLUSIVE VENUE FOR THE RESOLUTION OF ANY DISPUTE RELATING TO THIS AGREEMENT OR EXECUTIVE'S EMPLOYMENT (THAT IS NOT SUBJECT TO ARBITRATION UNDER SECTION 17 FOR ANY REASON) SHALL BE IN THE STATE AND FEDERAL COURTS LOCATED IN HARRIS COUNTY, TEXAS AND THE PARTIES HEREBY EXPRESSLY CONSENT TO THE JURISDICTION OF THOSE COURTS.

19. Entire Agreement and Amendment. This Agreement contains the entire agreement of the parties with respect to Executive's employment and the other matters covered herein (except to the extent that other agreements are specifically referenced herein); moreover, this Agreement supersedes all prior and contemporaneous agreements and understandings, oral or written, between the parties hereto concerning the subject matter hereof and thereof. This Agreement may be amended, waived or terminated only by a written instrument executed by both parties hereto.

20. Survival of Certain Provisions. Wherever appropriate to the intention of the parties hereto, the respective rights and obligations of said parties, including, but not limited to,

the rights and obligations set forth in Sections 6 through 18 hereof, shall survive any termination or expiration of this Agreement for any reason.

21. Waiver of Breach. No waiver by either party hereto of a breach of any provision of this Agreement by the other party, or of compliance with any condition or provision of this Agreement to be performed by such other party, will operate or be construed as a waiver of any subsequent breach by such other party or any similar or dissimilar provision or condition at the same or any subsequent time. The failure of either party hereto to take any action by reason of any breach will not deprive such party of the right to take action at any time while such breach continues.

22. Assignment. Neither this Agreement nor any rights or obligations hereunder shall be assignable or otherwise subject to hypothecation by Executive (except by will or by operation of the laws of intestate succession) or by the Company, except that the Company may assign this Agreement to any successor (whether by merger, purchase or otherwise) to all or substantially all of the equity, assets or businesses of the Company, if such successor expressly agrees to assume the obligations of the Company hereunder.

23. Notices. Notices provided for in this Agreement shall be in writing and shall be deemed to have been duly received (a) when delivered in person or sent by facsimile transmission, (b) on the first business day after such notice is sent by air express overnight courier service, or (c) on the third business day following deposit in the United States mail, registered or certified mail, return receipt requested, postage prepaid and addressed, to the following address, as applicable:

- (1) If to Company, addressed to:

Mariner Energy, Inc.
Attn: Chief Executive Officer
2101 Citywest Blvd.
19th Floor, Bldg. 2
Houston, TX 77042

- (2) If to Executive, addressed to the address set forth below Executive's name on the execution page hereof;

or to such other address as either party may have furnished to the other party in writing in accordance with this Section 23.

24. Counterparts. This Agreement may be executed in any number of counterparts, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute one and the same instrument. Each counterpart may consist of a copy hereof containing multiple signature pages, each signed by one party, but together signed by both parties hereto.

25. Definitions. The parties agree that as used in this Agreement the following terms shall have the following meanings: an “affiliate” of a person shall mean any person directly or indirectly controlling, controlled by, or under common control with, such person; the terms “controlling, controlled by, or under common control with” shall mean the possession, directly or indirectly, of the power to direct or influence or cause the direction or influence of management or policies (whether through ownership of securities or other ownership interest or right, by contract or otherwise) of a person; the term “person” shall mean a natural person, partnership (general or limited), limited liability company, trust, estate, association, corporation, custodian, nominee, or any other individual or entity in its own or any representative capacity, in each case, whether domestic or foreign.

SIGNATURE PAGE FOLLOWS

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IN WITNESS WHEREOF, Executive and the Company have executed this Agreement to be effective for all purposes as of the Effective Date.

EXECUTIVE:

Signature: /s/ Jesus Melendrez
Jesus Melendrez

Date: _____

Address for Notices:

**5301 Pocahontas
Bellaire, TX 77401**

MARINER ENERGY, INC.

By: /s/ Scott D. Josey
Scott D. Josey
Chief Executive Officer and President

Date: _____

Exhibit A

NONE

A-1

WAIVER AND RELEASE AGREEMENT

This Waiver and Release Agreement (the “**Agreement**”) is between Mariner Energy, Inc., a Delaware company (“**Company**”), and **Jesus Melendrez** (“**Executive**”), as provided pursuant to that employment agreement between Executive and Company dated February 7, 2005 (the “**Employment Agreement**”) and attached hereto as **Exhibit A**.

WHEREAS, Executive’s employment with Company is being terminated; and

WHEREAS, Executive will be paid certain severance benefits in exchange for his release and waiver of his claims against the Company Releasee (as defined below) pursuant to this Agreement;

NOW, THEREFORE, the parties agree to the following.

1. Complete Release and Other Consideration from Executive. In exchange for the severance benefits provided under Section 2 of this Agreement, Executive agrees as follows:

- a. Complete Release. On behalf of Executive and Executive’s heirs and assigns, Executive fully releases Company and its direct and indirect, past present and future, parents, subsidiaries, affiliates, divisions, predecessors, successors, and assigns, and, with respect to all such entities, their partners, members, shareholders, owners, officers, directors, attorneys, agents, representatives and employees (collectively, the “**Company Releasees**”), from any and all claims, demands, damages, losses, expenses, liabilities and causes of action (including claims for attorneys’ fees) (collectively, “**Claims**”), known or unknown, that Executive, his heirs, executors, administrators, and assigns may have or may claim to have against any of the Company Releasees based upon facts occurring on or prior to the date Executive signs this Agreement, including but not limited to any claims arising out of Executive’s employment relationship with and service as an employee, officer or director of Company, and the termination of such relationship or service, (the “**Release**”); *provided, however*, that this Release shall not apply to Company’s obligations under this Agreement. This Release includes, without limitation, any claims arising out of any contract (express or implied); any tort (whether based on negligent, grossly negligent, or intentional conduct); or any federal, state, or local law, including, without limitation, the Age Discrimination in Employment Act and the Employee Retirement Income Security Act (“ERISA”), other than benefits that Executive is entitled to under the terms of an ERISA plan. This Release does not include any claims under the Age Discrimination in Employment Act that may arise after this Agreement is executed.

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- b. Confidentiality. Except as may be required by law or court order or as may be necessary in an action arising out of this Agreement, Executive agrees not to disclose the existence or terms of this Agreement to anyone other than Executive's immediate family, attorneys, tax advisors, and financial counselors, provided that Executive first informs them of this confidentiality clause and secures their agreement to be bound by it. Executive understands and agrees that a breach of this confidentiality provision by any of these authorized persons will be deemed a material breach of this Agreement by Executive.
- c. Executive agrees not to bring or join any lawsuit against any of the Company Releasees in any court (except as necessary to protect Executive's rights under this Agreement or with respect to Executive's entry into this Agreement) relating to Executive's employment, events occurring during Executive's employment or the termination of Executive's employment. Executive represents that, as of the effective date of this Agreement, Executive has not brought or joined any lawsuit or filed any charge or claim against any of the Company Releasees in any court or before any government agency. If Executive brings or joins any lawsuit against any of the Company Releasees in any court (except as necessary to protect Executive's rights under this Agreement or with respect to Executive's entry into this Agreement) relating to Executive's employment, events occurring during Executive's employment or the termination of Executive's employment, and Executive is the prevailing party in such lawsuit, Executive shall be obligated to return to the Company all amounts paid to Executive as benefits under this Agreement, to the extent permitted under applicable law and ordered by the court. Further, if any Company Releasee is the prevailing party in any lawsuit Executive brings against such Company Releasee relating to Executive's employment that has been waived in this Agreement, to the extent permitted by applicable law (such as if Executive's claims are found to be brought in bad faith), Executive agrees to pay all costs and expenses incurred by such person or entity, including reasonable attorneys' fees, in defending against such lawsuit.

This Agreement is not intended to indicate that any Claims exist or that, if they do exist, they are meritorious. Rather, Executive is simply agreeing that, in return for the Company's payment provided by this Agreement, any and all potential Claims that Executive may have against the Company Releasees, regardless of whether they actually exist, are expressly settled, compromised and waived. By signing this Agreement, Executive and the Company Releasees are bound by it. Anyone who succeeds to Executive's rights and responsibilities, such as heirs or the executor of Executive's estate, is also bound by this Agreement. The waiver and release provisions of this Agreement do not apply to any rights or claims that may arise after its effective date. This Release also applies to any claims brought by any person or agency or class action under which Executive may have a right or benefit.

2. Consideration from Company. In exchange for Executive's obligations under this Agreement, the Company shall pay Executive those severance payments and benefits described in Sections 7, 8 and 9, as applicable, of the Employment Agreement, which are incorporated herein by reference and made a part of this Agreement. Executive acknowledges that Executive is not otherwise entitled to receive such severance payments and benefits, these severance payments and benefits are conditioned on Executive's compliance with the terms of this Agreement and the Employment Agreement, including without limitation Sections 11 and 12 thereof. Executive acknowledges and agrees that Company will withhold any taxes required by applicable law from the severance payments and benefits.

3. Right to Consult an Attorney; Period of Review. Executive is encouraged to consult with an attorney before signing this Agreement. From the date this Agreement is first presented to Executive, Executive will have 21 [45, if applicable] days in which to review this Agreement. Executive may use as little or much of this 21 [45]-day review period as Executive chooses.

4. Entire Agreement; Amendment; Continuing Obligations. This Agreement and the Employment Agreement together contain the entire agreement of the parties with respect to the termination of Executive's employment and the other matters covered herein and therein; moreover, this Agreement supersedes all prior and contemporaneous agreements and understandings, oral or written, between the parties hereto concerning the subject matter hereof. This Agreement may be amended, waived or terminated only by a written instrument executed by both parties hereto. Executive hereby reaffirms and agrees to continue to abide by all of Executive's continuing obligations under Sections 11 through 18 of the Employment Agreement.

5. Revocation. Upon signing this Agreement, Executive will have 7 days to revoke the Agreement. To properly revoke the Agreement, Company must receive written notice of revocation from Executive by the close of business on the 7th day after the date the Agreement is signed by Executive. Written notice must be delivered pursuant to Section 23 of the Employment Agreement. Executive understands that failure to revoke his acceptance of this Agreement within 7 days after the date he signs it will result in this Agreement being permanent and irrevocable.

6. Choice of Law. This Agreement will be governed in all respects by the laws of the State of Texas, without regard to its choice of law principles. This Agreement is subject to the arbitration provisions in Section 17 of the Employment Agreement.

7. Effectiveness of Agreement. This Agreement will be effective, and the severance payments and benefits provided in Section 2 of this Agreement will be made and provided, only if Executive executes this Agreement within 21 [45] days of receiving it and only if Executive does not revoke this Agreement under Section 5 above.

EXECUTIVE

Signature: _____
Jesus Melendrez

Date: _____

MARINER ENERGY, INC.

By: _____
[Name]
[Title]

Date: _____

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AMENDMENT TO EMPLOYMENT AGREEMENT

This Amendment to Employment Agreement (this “Amendment”) is made and entered into as of June 8, 2006 (the “Effective Date”), by and between Mariner Energy, Inc., a Delaware corporation (the “Company”), and Jesus Melendrez (“Executive”).

WHEREAS, the Company and Executive have previously entered into the Employment Agreement dated as of February 7, 2005 (the “Employment Agreement”), and desire to amend the Employment Agreement as set forth below.

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties, the Company and Executive hereby agree as follows:

1. Amendment. Section 8(a) of the Employment Agreement is hereby amended to read in its entirety as follows:

“8. Change of Control.

“(a) Upon the termination of Executive’s employment with the Company for any reason other than Cause at any time on or within nine months after a Change of Control that occurs during the Employment Period or upon the occurrence of a Change of Control within nine months following a termination of Executive’s employment that entitles Executive to severance under Section 7(c), the Company shall pay Executive, subject to Section 8(d) below, an amount equal to 2.5 times the sum of Executive’s Base Salary plus his Average Bonus Amount. The Executive’s “Average Bonus Amount” shall be the average annual amount paid or payable to Executive as bonuses for the Company’s three calendar years ended immediately prior to the occurrence of the Change of Control (or for the number of calendar years that Executive has been an employee of the Company before the occurrence of the Change of Control, if less than three); provided that any payment otherwise payable under this Section 8(a) shall be subject to Section 7(h) notwithstanding that such payment is not a severance payment.”

2. Governing Law. THIS AMENDMENT WILL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, WITHOUT REFERENCE TO PRINCIPLES OF CONFLICT OF LAWS.

3. Entire Agreement and Amendment. The Employment Agreement and this Amendment contain the entire agreement of the parties with respect to Executive’s employment and the other matters covered herein (except to the extent that other agreements are specifically referenced therein or herein).

4. Counterparts. This Amendment may be executed in any number of counterparts, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute one and the same instrument. Each counterpart may consist

of a copy hereof containing multiple signature pages, each signed by one party, but together signed by both parties hereto.

5. Code Section 409A Compliance. Notwithstanding anything in the Employment Agreement or this Amendment to the contrary, if any provision thereof or hereof would result in the imposition of an additional tax under Code Section 409A and related regulations and Treasury pronouncements (“Section 409A”), that provision will be reformed to avoid imposition of the applicable tax and no action taken to comply with Section 409A shall be deemed to adversely affect Executive’s rights under the Employment Agreement, as amended hereby.

IN WITNESS WHEREOF, Executive and the Company have executed this Amendment to be effective for all purposes as of the Effective Date.

EXECUTIVE:

/s/ Jesus Melendrez

Jesus Melendrez

MARINER ENERGY, INC.

By: /s/ Scott D. Josey

Scott D. Josey
Chief Executive Officer
and President

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Mariner Energy, Inc.

Statement regarding Computation of Ratio of Earnings to Fixed Charges
(unaudited)

	For the Years Ended December 31,				
	2009	2008	2007	2006	2005
	(in thousands, except ratio)				
Earnings from continuing operations before fixed charges					
Income before taxes	(543,779)	(436,748)	221,259	188,806	61,775
Add: Fixed charges	86,456	67,308	56,173	40,592	9,042
Less: Capitalized interest	14,661	9,651	474	1,528	703
Earnings from continuing operations before fixed charges	(471,984)	(379,091)	276,958	227,870	70,114
Fixed Charges					
Interest expense, net of capitalized interest	70,134	56,399	54,665	38,275	8,172
Add: Capitalized interest	14,661	9,651	474	1,528	703
Add: Estimated interest portion of rental expenditures	1,092	689	465	400	167
Add: Amortization of discounts	569	569	569	389	—
Total Fixed Charges	86,456	67,308	56,173	40,592	9,042
Ratio of earnings to fixed charges (1)	—	—	4.93	5.61	7.75

- (1) Due to loss from operations in 2009 and 2008, the ratio coverage was less than 1:1. Mariner would have needed to generate additional earnings of \$558,440 and \$446,399 respectively, to achieve a coverage of 1:1 for that period.

Mariner Energy, Inc.

Subsidiaries

<u>Exact Name of Subsidiary</u>	<u>State or Other Jurisdiction of Incorporation or Organization</u>	<u>Name under which Subsidiary does Business</u>
Mariner Energy Resources, Inc.	Delaware	Mariner Energy Resources, Inc.
Mariner Gulf of Mexico LLC	Delaware	Mariner Gulf of Mexico LLC
Edge Petroleum Exploration Company	Delaware	Edge Petroleum Exploration Company
Miller Exploration Company	Delaware	Miller Exploration Company

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-132152, 333-132800 and 333-159683 on Form S-8 and Registration Statement Nos. 333-141742 and 333-159682 on Form S-3 of our report dated March 1, 2010, relating to the consolidated financial statements of Mariner Energy, Inc. (which expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Accounting Standards Update No. 2010-3, "*Oil and Gas Reserve Estimation and Disclosures*" and Accounting Standards Codification Topic 805, "*Business Combinations*"), and the effectiveness of Mariner Energy, Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Mariner Energy, Inc. for the year ended December 31, 2009.

/s/ Deloitte & Touche LLP

Houston, Texas

March 1, 2010



RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
 1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5218

FAX (713) 651-0849
 TELEPHONE (713) 651-9191

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Ryder Scott Company, L.P. hereby consents to the use of its name and information from its report regarding estimated proved reserves and future income attributable to those reserves and their present value as of December 31, 2009 in Mariner Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2009, and to the incorporation by reference thereof into Mariner Energy, Inc.'s previously filed Registration Statements (Nos. 333-132152, 333-132800 and 333-159683) on Form S-8 and Registration Statements (Nos. 333-141742 and 333-159682) on Form S-3.

Ryder Scott Company, L.P. hereby consents to the filing of its report dated February 1, 2010 as Exhibit 99.1 to Mariner Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2009.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
 TBPE Firm Registration No. F-1580

Houston, Texas
 March 1, 2010

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 TEL (303) 623-9147

FAX (403) 262-2790
 FAX (303) 623-4258

CERTIFICATIONS

I, Scott D. Josey, certify that:

(1) I have reviewed this report on Form 10-K of Mariner Energy, Inc.;

(2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

(3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

(4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

(5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2010

/s/ Scott D. Josey

Scott D. Josey,
Chairman of the Board,
Chief Executive Officer and President

CERTIFICATIONS

I, Jesus G. Melendrez, certify that:

(1) I have reviewed this report on Form 10-K of Mariner Energy, Inc.;

(2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

(3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

(4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

(5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2010

/s/ Jesus G. Melendrez

Jesus G. Melendrez,
Senior Vice President, Chief Commercial Officer,
Acting Chief Financial Officer and Treasurer

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350**

I, Scott D. Josey, Chairman of the Board, Chief Executive Officer and President (principal executive officer) of Mariner Energy, Inc. (the "Registrant"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge, based upon a review of the Annual Report on Form 10-K for the fiscal year ended December 31, 2009, of the Registrant (the "Report"):

(i) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

Date: March 1, 2010

/s/ Scott D. Josey

Scott D. Josey,
Chairman of the Board,
Chief Executive Officer and President

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350**

I, Jesus G. Melendrez, Senior Vice President, Chief Commercial Officer, Acting Chief Financial Officer and Treasurer (principal financial officer) of Mariner Energy, Inc. (the "Registrant"), certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge, based upon a review of the Annual Report on Form 10-K for the fiscal year ended December 31, 2009 of the Registrant (the "Report"):

(i) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

Date: March 1, 2010

/s/ Jesus G. Melendrez

Jesus G. Melendrez,
Senior Vice President, Chief Commercial Officer,
Acting Chief Financial Officer and Treasurer

MARINER ENERGY, INC.

**Estimated
Future Reserves and Income
Attributable to Certain
Leasehold and Royalty Interests
SEC Parameters
As of
December 31, 2009**

/s/ Edward J. Gibbon

Edward J. Gibbon, P.E.
TBPE License No. 52750
Senior Vice President



RYDER SCOTT COMPANY, L.P.
TBPE Firm License No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS



TBPE REGISTERED ENGINEERING FIRM
 F-1580
 1100 LOUISIANA SUITE 3800

HOUSTON, TEXAS 77002-5218

FAX (713) 651-0849
 TELEPHONE (713) 651-9191

February 1, 2010

Mariner Energy, Inc.
 2000 W. Sam Houston Parkway South
 Suite 2000
 Houston, Texas 77042-3622

Gentlemen:

At your request, we have prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Mariner Energy, Inc. (Mariner) as of December 31, 2009. The subject properties are located in the states of Alabama, Arkansas, Louisiana, Michigan, Mississippi, New Mexico, and Texas; in the state waters offshore Louisiana and Texas; and in the federal waters offshore Florida, Louisiana, and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The results of our third party study, completed on February 1, 2010, are presented herein. The properties reviewed by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Mariner.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2009, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
 Estimated Net Reserves and Income Data
 Certain Leasehold and Royalty Interests of
Mariner Energy, Inc.
As of December 31, 2009

	Proved			
	Developed		Undeveloped	Total Proved
	Producing	Non-Producing		
Net Remaining Reserves				
Oil/Condensate — Barrels	22,182,961	9,280,305	21,001,842	52,465,108
Plant Products — Barrels	17,429,676	2,694,628	13,360,078	33,484,382
Gas — MCF	263,841	143,004	164,591	571,436
Income Data				
Future Gross Revenue	\$ 2,648,174,750	\$ 1,132,664,329	\$ 2,122,729,000	\$ 5,903,568,079
Deductions	<u>1,207,597,398</u>	<u>558,057,336</u>	<u>1,463,012,375</u>	<u>3,228,667,109</u>
Future Net Income (FNI)	\$ 1,440,577,352	\$ 574,606,993	\$ 659,716,625	\$ 2,674,900,970
Discounted FNI @ 10%	\$ 900,920,312	\$ 449,118,773	\$ 152,155,094	\$ 1,502,194,179

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 FAX (303) 623-4258

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an “as sold” basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used at the request of Mariner. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.]

The future gross revenue is after the deduction of production taxes. The deductions are comprised of the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 67 percent and gas reserves account for the remaining 33 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income As of December 31, 2009 Total Proved
5	\$ 1,901,758,800
15	\$ 1,255,362,900
20	\$ 1,084,799,100
25	\$ 958,346,600

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10 (a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “Petroleum Reserves Definitions” is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled “Petroleum Reserves Definitions” in this report. The developed non-producing reserves included herein consist of the shut-in and behind pipe categories.

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No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. At Mariner's request, the volumes of proved gas reserves presented in this report for certain offshore properties include Mariner's net share of fuel gas used on the platform. For those properties, the operating expense was increased to reflect an economic offset to the revenues from the fuel gas, and the additional cost was calculated as though an equal amount of gas had been purchased for use as fuel. The total net proved reserves of fuel gas included in this report are estimated to be 7,012 MMcf.

While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may also increase or decrease from existing levels, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts.

Mariner's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, and various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Mariner owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The reserves for the properties included herein were estimated by performance methods or the volumetric method. In general, reserves attributable to producing wells and/or reservoirs were estimated by performance methods such as decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through December, 2009 in those cases where such data were considered to be definitive. In certain cases, producing reserves were estimated by the volumetric method where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. Certain reserves attributable to non-producing and undeveloped reservoirs included herein were estimated by the volumetric method which utilized all pertinent well and seismic data available through December, 2009. Approximately 40% of the reserves included herein were estimated using the volumetric method. We utilized all methods and procedures that we deemed necessary to estimate Mariner's proved reserves, and we affirm that those methods and procedures were appropriate for this purpose.

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To estimate economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be demonstrated to be economically producible based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined as of the effective date of the report. Mariner has informed us that they have furnished us all of the accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future production and income, we have relied upon data furnished by Mariner with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data supplied by Mariner.

Future Production Rates

Our forecasts of future production rates are based on historical performance from wells now on production. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Mariner.

The future production rates from wells now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates.

Hydrocarbon Prices

As previously stated, the hydrocarbon prices used herein are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described. Product prices which were actually used for each property reflect adjustment for gravity, quality, local conditions, and/or distance from market.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

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Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Mariner and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. When applicable for operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Mariner and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The estimated net cost of abandonment after salvage was included for offshore properties where abandonment costs net of salvage was significant. The estimates of the net abandonment costs furnished by Mariner were accepted without independent verification. Mariner's estimates of zero abandonment costs after salvage value for onshore properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage values and makes no warranty for Mariner's estimates.

Because of the direct relationship between volumes of proved undeveloped reserves and development plans, we include in the proved undeveloped category only reserves assigned to undeveloped locations that we have been assured will definitely be drilled. Mariner has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans.

Current costs used by Mariner were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

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We are independent petroleum engineers with respect to Mariner. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The professional qualifications of the undersigned, the technical person primarily responsible for reviewing and approving the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

This report was prepared for the exclusive use and sole benefit of Mariner Energy, Inc. and may not be put to other use without our prior written consent for such use. The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Edward J. Gibbon
Edward J. Gibbon, P.E.
TBPE License No. 52750
Senior Vice President

EJG/sm



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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Edward J. Gibbon was the primary technical person responsible for overseeing the estimate of the reserves, future production and income.

Mr. Gibbon, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2003, is a Senior Vice President and also serves as an Engineering Group Coordinator responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies throughout North America. Before joining Ryder Scott, Mr. Gibbon served in a number of engineering positions with Tenneco Oil Company, Pogo Producing Company, North Central Oil Corporation, Texas General Petroleum Corp., IDM Engineering, Inc., Tatham Offshore, Inc., and Harken Energy Corp. For more information regarding Mr. Gibbon's geographic and job specific experience, please refer to the Ryder Scott Company website at <http://www.ryderscott.com/Experience/Employees.php>.

Mr. Gibbon earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1968 and is a Licensed Professional Engineer in the State of Texas and a Registered Professional Engineer in the State of Louisiana. He is also a member of the Society of Petroleum Evaluation Engineers (for which he presently serves as a Director), the Society of Petroleum Engineers, and the Society of Petrophysicists and Well Log Analysts.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gibbon fulfills. As part of his 2009 continuing education hours, Mr. Gibbon attended an internally presented 12 hours of formalized training as well as two presentations at professional society meetings by Dr. John Lee relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Gibbon attended an additional 4 hours of formalized in-house training as well as 32 hours of formalized external training during 2009 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 41 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gibbon has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

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PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (“the Commission”) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC Regulations”. The SEC Regulations take effect with all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10 (a) for the complete definitions, as the following definitions, descriptions and explanations rely wholly or in part on excerpts from the original document (direct passages excerpted from the aforementioned SEC document are denoted in italics herein).

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward under defined conditions. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC Regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the Commission. The SEC Regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the Commission unless such information is required to be disclosed in the document by foreign or state law as noted in §229.102 (5).

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

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RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) *The area of the reservoir considered as proved includes:*

(A) *The area identified by drilling and limited by fluid contacts, if any, and*

(B) *Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.*

(ii) *In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.*

(iii) *Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.*

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RESERVES DEFINITIONS

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(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir; or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs.

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and*
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

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Shut-In

Shut-in Reserves are expected to be recovered from:

- (1) completion intervals which are open at the time of the estimate but which have not yet started producing;*
- (2) wells which were shut-in for market conditions or pipeline connections; or*
- (3) wells not capable of production for mechanical reasons.*

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

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