MARINER ENERGY INC
Form 10-K
March 01, 2010

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

Form 10-K

þ 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

o 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	86-0460233
(State or other jurisdiction of incorporation or organization)	*(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 þ No o

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 o No þ

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 þ No o

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 o No o

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. o

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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 futu 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.

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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. Cert 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 a 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

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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:

	Operator	Approximate Working Interest %	2009 Net Production(2) (Bcfe)	Net Estimated Proved Reserves (Bcfe)	Estimated Proved Reserves % Oil /% Gas(1)
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.

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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.

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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.

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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.

	Estimated Proved Developed Reserve Quantities	Estimated Proved Undeveloped Reserve Quantities	Estimated Proved

Geographic Area	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (Bcfe)	Reserve Quantities 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	Developed	PV10 Value(1) Undeveloped (In millions)	Total	Standardized Measure (In millions)
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[tm] 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 indicted 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

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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
	32,665	22,864	101,336	73,508	32,454	25,150	147,229	107,414

Gulf of Mexico Shelf								
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

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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

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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.

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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

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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 on 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).

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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, stora 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.

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Employees