NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 26, 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**
For the transition period from to

Commission file number: 1-12534
Newfield Exploration Company
(Exact name of registrant as specified in its charter)

Delaware	**72-1133047**
(State of incorporation)	*(I.R.S. Employer Identification No.)*
363 North Sam Houston Parkway East, Suite 100, Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:
281-847-6000

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01 per share	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 15(d) of the 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 Securities Exchange Act of 1934 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 þ 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 Act). Yes o No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $4.3 billion as of June 30, 2009 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 22, 2010, there were 133,063,941 shares of the registrant s common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 7, 2010, which is incorporated by reference to the extent specified in Part III of this Form 10-K.

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If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption Commonly Used Oil and Gas Terms at the end of Items 1 and 2 of this report. Unless the context otherwise requires, all references in this report to Newfield, we, us or our are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest.

Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results, such as planned capital expenditures, future drilling plans and programs, expected production rates, the availability and sources of capital resources to fund capital expenditures, estimates of proved and probable reserves and the estimated present value of proved reserves, our financing plans and our business strategy and other plans and objectives for future operations. Although we believe that these expectations are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including:

oil and gas prices;

general economic, financial, industry or business conditions;

the impact of governmental regulations;

the availability and cost of capital to fund our operations and business strategies;

the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;

the availability of refining capacity for the crude oil we produce from our Monument Butte field;

drilling results;

the prices of goods and services;

the availability of drilling rigs and other support services;

labor conditions;

weather conditions, and changes in weather patterns, including adverse conditions and changes in patterns due to climate change;

the effect of worldwide energy conservation measures;

the price and availability of, and demand for, competing energy sources; and

the other factors affecting our business described below under the caption Risk Factors.

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. See Items 1 and 2, *Business and Properties*, Item 1A, *Risk Factors*, Item 3, *Legal Proceedings*, Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations* and Item 7A, *Quantitative and Qualitative Disclosures About Market Risk* for additional information about factors that may affect our businesses and operating results. These factors are not necessarily all of the important factors that could affect us. Use caution and common sense when considering these forward-looking statements. We do not intend to update these statements unless securities laws require us to do so.

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PART I

Items 1 and 2. *Business and Properties*

We are an independent oil and gas company engaged in the exploration, development and acquisition of oil and gas properties. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the Rocky Mountains, onshore Texas and the Gulf of Mexico. Internationally, we are also active in Malaysia and China.

General information about us can be found at *www.newfield.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the Securities and Exchange Commission. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

Overview

We are a Delaware corporation and were founded in 1989. Our company began as a Gulf of Mexico focused company. Over the last decade, we have diversified our asset base and added multiple areas capable of sustainable growth. Our asset base and related capital programs are diversified both geographically and by type offshore and onshore, domestic and international, conventional plays and unconventional resource plays in both oil and gas basins. Approximately 80% of our proved reserves and 85% of our probable reserves at year-end 2009 were located in resource plays, primarily in the Mid-Continent and the Rocky Mountains. Approximately 60% of our 2009 capital investments were allocated to growth opportunities in these regions. We expect our 2010 investment levels in these areas to be similar.

At year-end 2009, we had proved reserves of 3.6 Tcfe, a 23% increase over proved reserves at year-end 2008. At the end of 2009, our proved reserves were 72% natural gas and 53% proved developed. Our probable reserves were 70% natural gas. As a result of our focus on resource plays, our year-end 2009 proved reserve life index was approximately 14 years. Our 2009 production was 257 Bcfe.

2009 Proved Reserves by Area	2009 Probable Reserves by Area	2010 Estimated Production by Area
3.6 Tcfe	1.9 Tcfe	278-288 Bcfe

Strategy

Our growth strategy has evolved since our company was founded in 1989 and has allowed us to move into new unconventional plays, lengthen our reserves life and build a portfolio capable of sustainable future growth. Our strategy today consists of the following key elements:

- focusing on unconventional, domestic resource plays of scale, characterized by large acreage positions and deep inventories of low risk drilling opportunities;

- growing reserves through an active drilling program, supplemented with select acquisitions;

focusing on select geographic areas and allocating capital to the best growth opportunities;

controlling operations and costs; and

attracting and retaining a quality workforce through equity ownership and other performance-based incentives.

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Focus on Unconventional Resource Plays of Scale. Over the last several years, our industry has increased its focus on unconventional resources. We have been no exception and now own interests in more than 1 million gross acres in resource plays. These plays cover large acreage positions and have years of lower-risk drilling opportunities. Their development allows for efficiency gains in the drilling and completion processes, as well as sustainable and repeatable growth profiles. Our unconventional resource plays include producing positions in the Woodford Shale of Oklahoma, the Granite Wash of Texas, the Uinta Basin of Utah and the Eagle Ford and Pearsall Shales of southwest Texas. We also have leased acreage in the Marcellus Shale of Pennsylvania and the Southern Alberta Basin of Montana.

Drilling Program. The components of our drilling program reflect the significant changes in our asset base over the last few years. To manage the risks associated with our strategy to grow reserves through our drilling programs, a substantial majority of the wells we drilled in 2009 were lower-risk with low to moderate reserve potential. We have lower-risk drilling opportunities in the Mid-Continent, the Rocky Mountains and the shallow waters of Malaysia. These opportunities are complemented with higher-risk, higher reserve potential plays in deepwater areas like the Gulf of Mexico and Malaysia. We actively look for new drilling ideas on our existing property base and on properties that may be acquired.

Acquisitions. Acquisitions have consistently been a part of our strategy, particularly when entering new geographic regions. Since 2000, we have completed five significant acquisitions that led to the establishment of new focus areas onshore in the United States. We actively pursue acquisitions of proved oil and gas properties in select geographic areas, including those areas where we currently focus. The potential to add reserves through drilling is a critical consideration in our acquisition screening process. See Recent Developments below.

Geographic Focus. We believe that our long-term success requires extensive knowledge of the geologic and operating conditions in the areas where we operate. Because of this belief, we focus our efforts on a limited number of geographic areas where we can use our core competencies and have a significant influence on operations. Geographic focus also allows more efficient use of capital and personnel.

Control of Operations and Costs. In general, we prefer to operate our properties. By controlling operations, we can better manage production performance, control operating expenses and capital expenditures, consider the application of technologies and influence timing. At year-end 2009, we operated a significant portion of our net total production.

Equity Ownership and Incentive Compensation. We want our employees to act like owners, so we reward and encourage them through equity ownership and performance-based compensation. A large portion of our employees compensation is tied to our performance.

2010 Outlook and Capital Investments

Our 2010 capital budget is $1.6 billion, including approximately $124 million of estimated capitalized interest and overhead. We expect our 2010 production to grow 8-12% over 2009 levels. Our diversified portfolio of assets provides us with flexibility in our capital allocation process. We have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

For 2010, approximately 70% of our natural gas production and 40% of our oil production is hedged. For a complete discussion of our hedging activities, a listing of open contracts as of December 31, 2009 and the estimated fair value of these contracts as of that date, see Note 5, Derivative Financial Instruments, to our consolidated financial statements.

Our estimated 2010 capital investments by area are shown in the chart below:

$1.6 Billion

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Our Properties and Plans for 2010

Resource Plays

A key element of our strategy is to focus on domestic, unconventional resource plays of scale. These plays represent approximately 80% of our proved reserves and 85% of our probable reserves at year-end 2009.

Mid-Continent. Our largest business unit in terms of production, reserves and capital investment is the Mid-Continent. It has been our fastest growing business unit over the last several years. We are focused primarily in the Anadarko and Arkoma Basins. As of December 31, 2009, we owned a working interest in approximately 725,000 gross acres (approximately 400,000 net acres) and approximately 2,300 gross producing wells. This region is characterized by longer-lived natural gas production.

Woodford Shale. Our largest single investment area over the last several years has been the Woodford Shale in our Mid-Continent division, located in the Arkoma Basin of southeast Oklahoma. The Woodford is a shale formation that varies in thickness from 100 to 200 feet throughout our acreage. Our activities began in this area in 2003. At year-end 2009, we owned an interest in approximately 166,500 net acres. Our average working interest is approximately 60%. Since 2003, we have drilled more than 100 vertical wells and approximately 300 horizontal wells. We are currently running eight operated rigs on the acreage and expect to run six to eight operated rigs throughout 2010.

Our 2009 production in the Woodford Shale was 26% higher than our 2008 production, despite voluntary curtailments of approximately 3 Bcfe of natural gas production related to low gas prices in the second half of 2009. As of February 15, 2010, our operated production in the Woodford Shale was approximately 190 MMcfe/d net.

We expect our production in the Woodford Shale to grow more than 25% during 2010. Substantially all of our acreage is held-by-production. Our development plans for the field include drilling several thousand wells on primarily 40-acre spacing. We have improved efficiencies in the play through the drilling of horizontal wells with longer lateral completions. Our average lateral length has doubled since 2006 to a 2009 average of approximately 5,000 , and we expect our average length to be approximately 6,000 in 2010.

Granite Wash. We are active in the Granite Wash play located in the Anadarko Basin of northern Texas and western Oklahoma and have more than 44,000 net acres in the play. Our largest producing field in the Granite Wash is Stiles/Britt Ranch, where we operate and own an average 75% working interest. Although we have approximately 150 producing vertical wells in Stiles/Britt Ranch, our recent efforts have shifted to horizontal drilling. Since late 2008, we have drilled and completed 13 horizontal wells in the Granite Wash and the average initial production for these wells was approximately 20 MMcfe/d (gross). During 2009, we ran three to four operated drilling rigs in the field with production as of February 15, 2010 of approximately 130 MMcfe/d net. We expect to continue this level of activity in the Granite Wash, and expect our production in the Granite Wash to grow more than 25% during 2010. We have an inventory of approximately 250 locations in the Granite Wash.

Rocky Mountains. As of December 31, 2009, we owned an interest in approximately 1.4 million gross acres (1 million net acres) and more than 2,400 gross producing wells in the Rocky Mountains. Our assets in the Rocky Mountains are more than 70% oil and have long-lived production. Our efforts today are focused primarily on oil plays in the Uinta, Williston and Southern Alberta Basins.

Monument Butte. Our largest asset in the Rocky Mountains is the Monument Butte oil field, located in the Uinta Basin of Utah. Our working interest in the field averages about 80% and we operate the field, which is substantially

held-by-production. The field accounted for approximately 20% of our year-end 2009 proved reserves. We have approximately 1,300 productive oil wells in Monument Butte. Our acreage in this region is approximately 180,000 net acres. This includes 63,000 net acres that we have added over the last two years through several transactions with Ute Energy LLC. These lands adjoin Monument Butte at the field s northern edge. Since 2008, we have drilled approximately 75 wells on the Ute acreage. Our gross production from the Monument Butte field area has grown from 7,000 BOPD in 2004 to a February 15, 2010 rate of approximately 17,000 BOPD gross. In 2010, we are planning to drill a substantial portion of the acreage on 20-acre

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development spacing and estimate that we have thousands of remaining locations in the Monument Butte field area. There is a significant gas resource beneath the shallow producing oil zones at Monument Butte. In 2008, we participated in the drilling of six successful deep test wells to evaluate these deeper formations. Our 2010 plans include drilling our first horizontal well to test these deep gas objectives beneath Monument Butte.

Williston Basin/Southern Alberta Basin. We have approximately 150,000 net acres in the Williston Basin, excluding approximately 54,000 net acres in the mature Elm Coulee field. To date, we have drilled 14 successful wells with production from the Bakken and Sanish/Three Forks formations. Our production at year-end 2009 was approximately 2,500 BOEPD net. We plan to run three operated rigs in 2010 and expect production in the Williston Basin to grow more than 40% during the year. We have an inventory of approximately 80 development locations primarily along the Nesson Anticline. In late 2009, we reached an agreement with the Blackfeet Nation covering approximately 156,000 net acres in the Southern Alberta Basin of northern Montana. Including this recent transaction, we now have approximately 221,000 net acres in the Southern Alberta Basin. Our 2010 plans include drilling up to 10 wells in the Southern Alberta Basin.

Green River Basin. We own interests in 4,000 net acres in the Pinedale Field, located in Sublette County, Wyoming and operate our activities in Pinedale. We also have an interest in the Jonah field, located in Sublette County, Wyoming, where we have identified about 35 development locations on 10- and 5-acre well spacing. Although we halted our activities in the Green River Basin with lower gas prices in 2009, we see the potential to drill approximately 120 additional locations as field spacing decreases to 20 acres and eventually to 10 acres. With improved realized gas prices in 2010, our activities here may resume in 2010.

Appalachia. In mid-2009, we signed a joint exploration agreement with Hess Corporation covering up to 140,000 gross acres in the Marcellus Shale play, primarily in Wayne County, Pennsylvania. We are the operator of this venture with a 50% working interest. At year-end 2009, we had leased about 35,000 net acres. This marked our entry into the Marcellus one of the nation s largest resource plays. The Marcellus is economically advantaged due to its close proximity to the gas markets of the Northeast. We are permitting our initial wells and expect to drill 6-10 assessment wells in 2010 to test for commercial quantities of gas, evaluate acreage and core data while determining how best to develop our acreage.

Conventional Plays

We also have operations in conventional plays onshore Texas, in the Gulf of Mexico and offshore Malaysia and China.

Onshore Texas. As of December 31, 2009, we owned an interest in approximately 375,000 gross acres (224,000 net) and about 750 gross producing wells onshore Texas. We slowed our activities in many of our conventional natural gas plays onshore Texas in 2009 in response to lower natural gas prices. At year-end 2009, we were producing approximately 170 MMcfe/d net from our onshore Texas assets. With planned decreased investments in 2010 and natural declines, we expect production from this area to decline approximately 15% during 2010. However, production from our recently acquired assets from TXCO Resources Inc. (TXCO) will add to our production, which should cause our 2010 production from onshore Texas to remain relatively flat. Our acquisition of assets from TXCO was our entry into the Maverick Basin of southwest Texas. We have multiple potential geologic targets for future development, primarily in the Eagle Ford and Pearsall Shales. See Recent Developments below.

Gulf of Mexico. Our Gulf of Mexico operations are focused on the deepwater. At year-end 2009, our daily production from the Gulf of Mexico was approximately 90 MMcfe/d net. We have five active deepwater developments underway that we expect will lead to significant future production growth. As of December 31, 2009, we owned interests in 86 deepwater leases and approximately 370,000 net acres. We have an inventory of prospects acquired primarily through

federal lease sales over the last several years and we expect to drill three to five wells per year for the next several years. Our working interests typically range from 20-50%. We expect our Gulf of Mexico production to grow more than 60% during 2010.

International. Our international activities are focused in Southeast Asia. We have production and active developments offshore Malaysia and China. Our international production at year-end 2009 was approximately

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17,000 BOPD net. We have an interest in approximately 3 million acres gross (1.1 million net) offshore Malaysia and approximately 1.7 million acres gross (1.6 million net) offshore China. In 2010, our plans include continued development of our oil fields offshore Malaysia. During 2010, we also plan to develop our 2009 Pearl discovery in the Pearl River Mouth Basin of China and plan to drill two exploratory commitment wells offshore China. We expect our international production to decline approximately 20% in 2010.

Recent Developments

On February 11, 2010, we acquired certain of TXCO s assets in the Maverick Basin of southwest Texas for $215 million. The assets we acquired include approximately 300,000 net acres and current net production of approximately 1,500 BOEPD, of which approximately two-thirds is oil.

Concentration

Reserves. The table below sets forth the concentration of our proved and probable reserves, by location, and the percentage of those reserves attributable to our largest fields. Our largest fields, the Woodford Shale and Monument Butte, accounted for about 40% of the total net present value of our proved reserves at December 31, 2009.

	Percentage of Proved Reserves	Percentage of Probable Reserves
Located domestically	95	92
Located onshore	90	88
10 largest fields	85	94
2 largest fields	64	80

Oil and Gas Production, Prices and Costs. The table below sets forth for our largest fields (those whose reserves are greater than 15% of our total proved reserves) the annual production volumes, realized prices and related production cost structure on a per unit of production basis. For a discussion regarding our total domestic and international annual production volumes, realized prices and related production cost structure on a per unit of production basis, see Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations* Results of Operations.

	Year Ended December 31,		
	2009	2008	2007
Production:			
Natural gas (Bcf)			
Monument Butte	4.5	5.1	5.2
Woodford Shale	61.4	52.1	23.8
Oil and condensate (MBbls)			
Monument Butte	4,080	3,471	2,859
Woodford Shale	37	10	4
Average Realized Prices:			
Natural gas (per Mcf)			
Monument Butte	$ 2.80	$ 3.62	$ 2.19
Woodford Shale	$ 3.19	$ 6.66	$ 5.67

Oil and condensate (per Bbl)			
Monument Butte	$ 48.21	$ 81.48	$ 56.61
Woodford Shale	$ 53.49	$ 97.23	$ 68.00
Production Cost:			
Monument Butte (per BOE)	$ 7.65	$ 9.66	$ 6.83
Woodford Shale (per Mcfe)	$ 0.82	$ 1.06	$ 1.20

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Proved and Probable Reserves

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data input into reserves forecasting and economics evaluation software, as well as multi-discipline management reviews, as described below. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 25 years of experience (including 15 years of experience in reserve estimation) and is a Registered Professional Engineer in Texas.

Our reserves estimates are made using available geological and reservoir data as well as production performance data. These estimates, made by our petroleum engineering staff, are reviewed annually with management and revised, either upward or downward, as warranted by additional data. The data reviewed includes, among other things, seismic data, well logs, production tests, reservoir pressures, individual well and field performance data. The data incorporated into our interpretations includes structure and isopach maps, individual well and field performance and other engineering and geological work products such as material balance calculations and reservoir simulation to arrive at conclusions about individual well and field projections. Additionally, offset performance data, operating expenses, capital costs and product prices factor into estimating quantities of reserves. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental regulations, as well as changes in the expected recovery rates associated with infill drilling. Sustained decreases in prices, for example, may cause a reduction in some reserves due to reaching economic limits sooner.

Actual quantities of reserves recovered will most likely vary from the estimates set forth below. Reserves and cash flow estimates rely on interpretations of data and require assumptions that may be inaccurate. For a discussion of these interpretations and assumptions, see *Actual quantities of oil and gas reserves and future cash flows from those reserves will most likely vary from our estimates* under Item 1A of this report. Our estimates of proved reserves, proved developed reserves and proved undeveloped reserves and future net cash flows and discounted future net cash flows from proved reserves at December 31, 2009, 2008 and 2007 and changes in proved reserves during the last three years are contained in Supplementary Financial Information Supplementary Oil and Gas Disclosures Estimated Net Quantities of Proved Oil and Gas Reserves in Item 8 of this report. For a discussion of the significant changes in our proved reserves during 2009, please see the information set forth in *Management s Discussion and Analysis of Financial Condition and Results of Operations* Proved Reserves in Item 7 of this report.

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The following table shows, by country and in the aggregate a summary of our proved and probable oil and gas reserves as of December 31, 2009.

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)[1]
Proved Developed Reserves:			
Domestic	70	1,397	1,820
International:			
Malaysia	10		60
China	5		28
Total International	15		88
Total Proved Developed	85	1,397	1,908
Proved Undeveloped Reserves:			
Domestic	66	1,208	1,604
International:			
Malaysia	16		91
China	2		13
Total International	18		104
Total Proved Undeveloped	84	1,208	1,708
Total Proved Reserves	169	2,605	3,616
Probable Developed Reserves:			
Domestic	9	29	83
International:			
Malaysia	3		18
China			
Total International	3		18
Total Probable Developed	12	29	101
Probable Undeveloped Reserves:			
Domestic	62	1,293	1,667
International:			
Malaysia	4		25
China	17		100
Total International	21		125
Total Probable Undeveloped	83	1,293	1,792

Total Probable Reserves	95	1,322	1,893

(1) Billion cubic feet equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

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Proved Reserves. Our year-end 2009 proved reserves of 3.6 Tcfe increased 23% as compared to our proved reserves at year-end 2008, and consisted of 1,505 Bcfe proved developed producing, 403 Bcfe proved developed non-producing and 1,708 Bcfe proved undeveloped reserves. Our 2009 proved reserves include 693 Bcfe of additions resulting from the change in the Securities and Exchange Commission (SEC) definition of proved reserves, expanding proved undeveloped reserve locations beyond one direct offset away from producing wells if such locations meet the definition of proved reserves.

At December 31, 2008 our estimated proved undeveloped reserves were 1,124 Bcfe. During 2009, we spent $364 million of drilling, completion and facilities-related capital to convert 123 Bcfe of our December 31, 2008 proved undeveloped reserves into proved developed reserves. Another 275 Bcfe of our beginning of year proved undeveloped reserves were removed from the proved undeveloped category during 2009, substantially all of which were no longer economic utilizing a natural gas price of $3.87 per MMBtu for our year-end 2009 reserve calculations. During 2009, we added 289 Bcfe of new proved undeveloped reserves through drilling activities. Additionally, we added 693 Bcfe of proved undeveloped reserves as a result of the change in the SEC definition of proved reserves expanding proved undeveloped reserve locations beyond one direct offset away from producing wells. These additions were primarily in our Woodford Shale and Monument Butte fields. Proved undeveloped reserve quantities were limited by the activity level of development drilling we expect to undertake during the 2010-2014 five-year period. Quantities of reserves that would otherwise meet the definition of proved undeveloped reserves except for the fact that they will be developed beyond the 2010-2014 five-year horizon (904 Bcfe) have been classified as probable reserves, in accordance with SEC regulations. As a result of the foregoing, our proved undeveloped reserves at December 31, 2009 were 1,708 Bcfe, 98% of which have been included in our reserve report for less than five years. For additional information regarding the changes in our proved reserves, see Proved Reserves under Item 7 of this report.

Probable Reserves. Our probable reserves at year-end 2009 consisted of 101 Bcfe developed and 1,792 Bcfe of undeveloped reserves. Included in our undeveloped probable reserves are 904 Bcfe that would otherwise meet the definition of proved undeveloped reserves except for the fact that they will not be developed during the 2010-2014 five-year horizon. A significant portion of these probable reserves are associated with our Woodford Shale activities.

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Reserves Sensitivities. To determine our year-end 2009 reserves estimates, we utilized the unweighted average first-day-of-the-month natural gas and crude oil prices for the prior twelve months, or $3.87 per MMBtu and $61.14 per barrel, respectively, adjusted for market differentials. In 2009, we experienced low average natural gas prices and, as a result, the estimated future net cash flows from our proved reserves are substantially lower than at year-end 2008 on a unit-of-reserve basis, but are substantially offset by higher quantities of proved reserves. The table below illustrates changes in the quantities of proved and probable reserves at various price scenarios, holding all other year-end reserve assumptions constant.

	Proved Reserves			Probable Reserves		
Price Case ($/MMBtu for Natural Gas and $/Bbl for Oil)	**Oil (MBbls)**	**Natural Gas (Bcf)**	**Total (Bcfe)**	**Oil (MBbls)**	**Natural Gas (Bcf)**	**Total (Bcfe)**
Assumed $3.87 and $50	164	2,597	3,582	92	1,317	1,870
Pricing per SEC rules $3.87 and $61.14	**169**	**2,605**	**3,616**	**95**	**1,323**	**1,893**
Assumed $3.87 and $70	170	2,609	3,630	94	1,323	1,886
Assumed $5 and $61.14	169	2,758	3,774	95	1,821	2,393

Our proved reserves increase at higher prices primarily as a result of extending the economic life of our proved developed reserves. Higher realized prices do not materially increase the quantity of our proved undeveloped reserves because it is limited by the level of development drilling we expect to undertake during the 2010-2014 five-year period. This limitation impacts our Woodford Shale (natural gas) and our Monument Butte field (crude oil) developments because of their size.

Our probable reserves increase approximately 500 Bcfe utilizing a $5.00 per MMBtu natural gas price instead of a $3.87 per MMBtu natural gas price, with no change in oil prices. The increase is attributable to quantities of reserves associated with our Woodford Shale activities that are not commercial at a $3.87 per MMBtu natural gas price. These probable reserves would meet the definition of proved undeveloped reserves except for the fact that they would be developed beyond the 2010-2014 five-year horizon. Accordingly, a total of approximately 1,404 Bcfe, or 60%, of our probable reserves at a $5.00 per MMBtu natural gas price would meet the definition of proved undeveloped reserves except for the fact that they would be developed beyond the 2010-2014 five-year horizon.

Our proved reserves decrease at lower crude oil prices as a result of shortening the economic life of our proved developed reserves. Crude oil prices at the levels shown in the table above would not change our development plans and, therefore, have no impact on the quantity of proved undeveloped reserves because that quantity is limited by the level of development drilling we expect to undertake during the 2010-2014 five-year period. Our proved undeveloped oil reserves lie primarily in our Monument Butte field.

Under the terms of our production sharing contracts in Malaysia and China, an increase or decrease in realized oil prices would result in a decrease or increase, respectively, in our proved reserves. At higher oil prices, lesser quantities of oil are required for cost recovery and at lower oil prices greater quantities of oil are required for cost recovery. Our share (the contractor s share) of future production is impacted accordingly. The effect of higher or lower oil prices may be partially offset by extending or shortening, respectively, the economic life of proved reserves.

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Drilling Activity

The following table sets forth our drilling activity for each year (other than drilling activity related to our operations in the United Kingdom, which were discontinued in 2007) in the three-year period ended December 31, 2009.

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive[1]	273	153.1	385	217.4	343	219.0
Nonproductive[2]	8	4.8	20	15.4	24	16.6
International:						
China:						
Productive[3]	1	1.0	2	1.1		
Nonproductive[4]			1	1.0		
Malaysia:						
Productive[5]	1	0.4	5	2.6	1	0.6
Nonproductive[6]					3	2.1
International Total:						
Productive	2	1.4	7	3.7	1	0.6
Nonproductive			1	1.0	3	2.1
Exploratory well total	283	159.3	413	237.5	371	238.3
Development wells:						
Domestic:						
Productive	128	98.7	175	138.2	135	105.7
Nonproductive			4	3.0	2	1.6
International:						
China:						
Productive	12	1.4	6	0.7	8	1.0
Nonproductive			2	0.2		
Malaysia:						
Productive	5	2.8	7	4.2	3	1.7
Nonproductive						
International Total:						
Productive	17	4.2	13	4.9	11	2.7
Nonproductive			2	0.2		
Development well total	145	102.9	194	146.3	148	110.0

(1) Includes 29 gross (17.7 net), 38 gross (27.1 net) and 19 gross (12 net) wells in 2009, 2008 and 2007, respectively, that are not exploitation wells.

(2) Includes 3 gross (1.3 net), 9 gross (7.5 net) and 15 gross (8.8 net) wells in 2009, 2008 and 2007, respectively, that are not exploitation wells.

(3) Includes 1 gross (1.0 net) well in each of 2009 and 2008 that is not an exploitation well.

(4) The well in 2008 is not an exploitation well.

(5) Includes 1 gross (0.4 net) and 2 gross (1.1 net) wells in 2009 and 2008, respectively, that are not exploitation wells.

(6) Includes 3 gross (2.1 net) wells in 2007 that are not exploitation wells.

We were in the process of drilling 36 gross (21.0 net) exploratory wells (includes 32 gross (18.6 net) exploitation wells) and 11 gross (8.2 net) development wells domestically at December 31, 2009. Internationally, we were drilling 1 gross (1.0 net) exploratory well in China at December 31, 2009. This well is not an exploitation well.

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Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest as of December 31, 2009 and the location of, and other information with respect to, those wells. As of December 31, 2009, we had 67 gross (53.4 net) gas wells and 5 gross (2.5 net) oil wells with multiple completions.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Offshore:						
Oil			2	0.5	2	0.5
Natural gas	5	3.3	2	0.6	7	3.9
Onshore:						
Oil	2,475	2,021.2	232	42.2	2,707	2,063.4
Natural gas	1,523	1,199.7	1,269	276.5	2,792	1,476.2
Total Domestic:						
Oil	2,475	2,021.2	234	42.7	2,709	2,063.9
Natural gas	1,528	1,203.0	1,271	277.1	2,799	1,480.1
International:						
Offshore China:						
Oil			34	4.1	34	4.1
Offshore Malaysia:						
Oil	12	7.2	22	11.0	34	18.2
Total International:						
Oil	12	7.2	56	15.1	68	22.3
Total:						
Oil	2,487	2,028.4	290	57.8	2,777	2,086.2
Natural gas	1,528	1,203.0	1,271	277.1	2,799	1,480.1
Total	4,015	3,231.4	1,561	334.9	5,576	3,566.3

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. Generally, an operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

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Acreage Data

As of December 31, 2009, we owned interests in developed and undeveloped oil and gas acreage set forth in the table below. Domestic ownership interests generally take the form of working interests in oil and gas leases that have varying terms. International ownership interests generally arise from participation in production sharing contracts.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Offshore	71	13	667	357
Onshore:				
Mid-Continent	612	340	115	53
Rocky Mountains	197	118	1,243	923
Gulf Coast	143	97	237	129
Appalachia			70	35
Total Onshore	952	555	1,665	1,140
Total Domestic	1,023	568	2,332	1,497
International:				
Offshore China	22	3	1,674	1,674
Offshore Malaysia	190	96	2,604	1,029
Total International	212	99	4,278	2,703
Total	1,235	667	6,610	4,200

The table below summarizes by year and geographic area our undeveloped acreage scheduled to expire in the next five years. In most cases, the drilling of a commercial well, or the filing and approval of a development plan or suspension of operations, will hold acreage beyond the expiration date. We own fee mineral interests in 374,480 gross (107,040 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring									
	2010		2011		2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Offshore	107	31	23	19	63	21	103	82	40	20
Onshore:										

Mid-Continent	230	27	87	8	188	17	19	1	1	
Rocky Mountains	349	289	200	155	63	51	31	20	38	27
Gulf Coast	105	52	47	20	15	9	18	14	7	5
Total Onshore	684	368	334	183	266	77	68	35	46	32
Total Domestic	791	399	357	202	329	98	171	117	86	52
International:										
Offshore China	1,292	1,292					382	382		
Offshore Malaysia	338	203	1,079	431			1,187	395		
Total International	1,630	1,495	1,079	431			1,569	777		
Total	2,421	1,894	1,436	633	329	98	1,740	894	86	52

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Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes, development obligations under oil and gas leases or capital commitments under production sharing contracts or exploration licenses. As is customary in the industry in the case of undeveloped properties, often little investigation of record title is made at the time of acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Marketing

Substantially all of our oil and gas production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market sensitive prices. For a list of purchasers of our oil and gas production that accounted for 10% or more of our consolidated revenue for the three preceding calendar years, please see Note 1, Organization and Summary of Significant Accounting Policies *Major Customers*, to our consolidated financial statements. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers are readily available with the exception of purchasers of our Monument Butte field oil production. Due to the higher paraffin content of this production, there is limited refining capacity for it. Please see the discussion under *There is limited refining capacity for our black wax crude oil, which may limit our ability to sell our current production or to increase our production at Monument Butte in the Uinta Basin* in Item 1A of this report.

Competition

Competition in the oil and gas industry is intense, particularly with respect to the hiring and retention of technical personnel, the acquisition of properties and access to drilling rigs and other services in the Gulf of Mexico. For a further discussion, please see the information regarding competition set forth in Item 1A of this report.

Employees

As of February 22, 2010, we had 1,148 employees. All but 101 of our employees were located in the U.S. None of our employees are covered by a collective bargaining agreement. We believe that relationships with our employees are satisfactory.

Regulation

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations. An overview of these regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption *We are subject to complex laws that can affect the cost, manner or feasibility of doing business. In addition, potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.* in Item 1A of this report.

Federal Regulation of Sales and Transportation of Natural Gas. Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural

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Gas Act (NGA) and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations. The Outer Continental Shelf Lands Act, or OCSLA, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its Natural Gas Act jurisdiction. Therefore, we do not believe that any FERC or MMS action taken under OCSLA will affect us in a way that materially differs from the way it will affect other natural gas producers, gatherers and marketers with which we compete.

Pursuant to authority enacted in the Energy Policy Act of 2005 (2005 EPA), FERC has promulgated anti-manipulation regulations, violations of which make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to use or employ any device, scheme, or artifice to defraud, to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity. Violation of this requirement, similar to violations of other NGA and FERC requirements, may be penalized by the FERC up to $1 million per day per violation. FERC may also order disgorgement of profit and corrective action. We believe, however, that neither the 2005 EPA nor the regulations promulgated by FERC as a result of the 2005 EPA will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Our sales of natural gas and crude are also subject to requirements under Commodity Exchange Act (CEA) and regulations promulgated thereunder by the Commodity Futures Trading Commission (CFTC). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, the CFTC and the courts. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. There is always some risk, however, that Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action the FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by the FERC and Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other crude oil and condensate producers.

Federal Leases. Many of our domestic oil and gas leases are granted by the federal government and administered by the MMS or the BLM, both federal agencies. MMS and BLM leases contain relatively standardized terms and require compliance with detailed BLM or MMS regulations and, in the case of offshore leases, orders pursuant to OCSLA (which are subject to change by the MMS). Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the time during which activities on the lease may be conducted, the manner in

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which certain activities may be conducted or, in some cases, may ban surface activity. For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency), lessees must obtain a permit from the BLM or the MMS, as applicable, prior to the commencement of drilling, and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Shelf and removal of facilities. To cover the various obligations of lessees on the Shelf, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases. We are currently exempt from the supplemental bonding requirements of the MMS. Under certain circumstances, the BLM or the MMS, as applicable, may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the MMS will collect royalties based upon the market value of oil produced from federal leases. The 2005 EPA formalizes the royalty in-kind program of the MMS, providing that the MMS may take royalties in-kind if the Secretary of the Interior determines that the benefits are greater than or equal to the benefits that are likely to have been received had royalties been taken in value. We believe that the MMS s royalty in-kind program will not have a material effect on our financial position, cash flows or results of operations.

In 2006, the MMS amended its regulations to require additional filing fees. The MMS has estimated that these additional filing fees will represent less than 0.1% of the revenues of companies with offshore operations in most cases. We do not believe that these additional filing fees will affect us in a way that materially differs from the way they affect other producers, gatherers and marketers with which we compete.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in a number of states and in state waters offshore Texas and Louisiana. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Environmental laws and regulations are complex, and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Moreover, some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

The Oil Pollution Act, or OPA, imposes regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from spills in U.S. waters. A responsible party includes the

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owner or operator of an onshore facility, vessel or pipeline, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns strict, joint and several liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of such limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages for offshore facilities and up to $350 million for onshore facilities. Few defenses exist to the liability imposed by OPA. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party to administrative, civil or criminal enforcement actions.

OPA also requires operators in the Gulf of Mexico to demonstrate to the MMS that they possess available financial resources that are sufficient to pay for costs that may be incurred in responding to an oil spill. Under OPA and implementing MMS regulations, responsible parties are required to demonstrate that they possess financial resources sufficient to pay for environmental cleanup and restoration costs of at least $10 million for an oil spill in state waters and at least $35 million for an oil spill in federal waters.

In addition to OPA, our discharges to waters of the U.S. are further limited by the federal Clean Water Act, or CWA, and analogous state laws. The CWA prohibits any discharge into waters of the United States except in compliance with permits issued by federal and state governmental agencies. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. The OPA and CWA also require the preparation of oil spill response plans and spill prevention, control and countermeasure or SPCC plans. We have such plans in place and have made changes as necessary due to changes by the U.S. Environmental Protection Agency, also known as the EPA, and delays in EPA rulemaking. The final EPA rule was published in November 2009 and became effective on January 14, 2010, with a compliance deadline of November 2010.

OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Shelf. Specific design and operational standards may apply to vessels, rigs, platforms, vehicles and structures operating or located on the Shelf. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial administrative, civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases.

The Resource Conservation and Recovery Act, or RCRA, generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although 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, natural gas or geothermal energy, the EPA and state agencies may regulate these wastes as solid wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a hazardous substance into the environment. Such responsible persons may be subject to joint and several liability under the Superfund law for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease onshore properties that have been used for the exploration and production of oil and gas for a number of years. Many of these onshore properties have been operated by third parties whose treatment and disposal or release of

hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been disposed or released on them may be subject to the Superfund law, RCRA and analogous state laws and common law obligations, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

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The Clean Air Act (CAA or the Clean Air Act) and comparable state statutes restrict the emission of air pollutants and affects both onshore and offshore oil and gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants, and is considering the regulation of additional air pollutants and air pollutant parameters. These regulations may increase the costs of compliance for some facilities.

The Occupational Safety and Health Act (OSHA) and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Congress has been actively considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which is now being considered by the U.S. Senate. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. Further, on April 2, 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an air pollutant under the federal Clean Air Act. On April 24, 2009, EPA responded to the Massachusetts, et al. v. EPA decision with a proposed finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change. EPA published the final version of this finding on December 15, 2009, which allowed EPA to proceed with the rulemaking process to regulate greenhouse gases under the Clean Air Act. In anticipation of the finalization of EPA s finding that greenhouse gases threaten public health and welfare, and that greenhouse gases from new motor vehicles contribute to climate change, EPA proposed a rule in September of 2009 that would require a reduction in emissions of greenhouse gases from motor vehicles and would trigger applicability of Clean Air Act permitting requirements for certain stationary sources of greenhouse gas emissions. In response to this issue, EPA also proposed a tailoring rule that would, in general, only impose greenhouse gas permitting requirements on facilities that emit more than 25,000 tons per year of greenhouse gases. Moreover, on September 22, 2009, EPA finalized a rule requiring nation-wide reporting of greenhouse gas emissions in 2011 for emissions occurring in 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year, and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

International Regulations. Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the respective governments of the countries in which we operate, and may affect our operations and costs within that country. We currently have operations in Malaysia and China.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

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Barrel or Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

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

BLM. The Bureau of Land Management of the United States Department of the Interior.

BOE. One barrel of oil equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or gas.

Deepwater. Generally considered to be water depths in excess of 1,000 feet.

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

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.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drilled in 2007, 2008 and 2009 and expect to drill in 2010 are located in the Mid-Continent or the Monument Butte field. Exploitation wells in those areas have less risk and less reserve potential and typically may be drilled at a lower cost than other exploration wells. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. An exploration well is 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. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

FERC. The Federal Energy Regulatory Commission.

FPSO. A floating production, storage and off-loading vessel commonly used overseas to produce oil from locations where pipeline infrastructure is not available.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

Infill drilling or infill well. A well drilled between known producing wells to improve oil and gas reserve recovery efficiency.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

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MMcfe/d. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate, produced per day.

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

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btus.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells, as the case may be.

NYMEX. The New York Mercantile Exchange.

NYMEX Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

Probable reserves. Probable reserves are 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. The SEC provides a complete definition of probable reserves in Rule 4-10(a)(18) of Regulation S-X.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves. In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves. Proved 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.

Proved undeveloped reserves. In general, proved reserves 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. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

Reserve life index. This index is calculated by dividing total proved reserves at year end by annual production to estimate the number of years of remaining production.

Shelf. The U.S. Outer Continental Shelf of the Gulf of Mexico. Water depths generally range from 50 feet to 1,000 feet.

Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

Unconventional resource plays. Plays targeting tight sand, coal bed or gas shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require stimulation treatments or other special recovery processes in order to produce economically.

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

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

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Item 1A. ***Risk Factors***

There are many factors that may affect Newfield s business and results of operations. You should carefully consider, in addition to the other information contained in this report, the risks described below.

Oil and gas prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas. Lower prices may reduce the amount of oil and gas that we can economically produce. Oil and gas prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount that we can borrow under our credit facility could be limited by changing expectations of future prices because the maximum amount that we may borrow under our credit facility is determined by our lenders annually each May, and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures, using a process that takes into account the value of our estimated reserves and hedge position and the lenders commodity price assumptions.

Among the factors that can cause fluctuations in oil and gas prices are:

- the domestic and foreign supply of oil, natural gas and natural gas liquids;
- the price and availability of, and demand for, alternative fuels;
- weather conditions and climate change;
- changes in supply and demand;
- world-wide economic conditions;
- the price of foreign imports;
- the availability, proximity and capacity of transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- political conditions in oil and gas producing regions; and
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulation.

We have substantial capital requirements to fund our business plans, and a slow recovery of the economy and the financial markets in 2010 or another decline or crisis as was experienced in late 2008 and 2009 could negatively impact our ability to execute our business plan. Although we anticipate that our 2010 capital spending, excluding acquisitions, will correspond with our anticipated 2010 cash flows, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We may have to reduce capital expenditures, and our ability to execute our business plans could be adversely affected, if (1) one or more of the lenders under our existing credit arrangements

fail to honor its contractual obligation to lend to us, (2) the amount that we are allowed to borrow under our existing credit facility is reduced as a result of lower oil and gas prices, declines in reserves, lending requirements or for other reasons or (3) our customers or working interest owners default on their obligations to us.

Our use of oil and gas price hedging contracts may limit future revenues from price increases and involves the risk that our counterparties may be unable to satisfy their obligations to us. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months as part of our risk management program. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our

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exposure to price volatility is intended to help ensure that we have adequate funds available for our capital programs and to help us manage returns on some of our acquisitions and more price sensitive drilling programs. Although the use of hedging transactions limits the downside risk of price declines, it also may limit the benefit from price increases and expose us to the risk of financial loss in certain circumstances. Those circumstances include instances where our production is less than the hedged volume or there is a widening of price basis differentials between delivery points for our production and the delivery points assumed in the hedge transaction.

Hedging transactions also involve the risk that counterparties, which generally are financial institutions, may be unable to satisfy their obligations to us. Although we have entered into hedging contracts with multiple counterparties to mitigate our exposure to any individual counterparty, if any of our counterparties were to default on its obligations to us under the hedging contracts or seek bankruptcy protection, it could have a material adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened, and it is possible that fewer counterparties will participate in future hedging transactions, which could result in greater concentration of our exposure to any one counterparty or a larger percentage of our future production being subject to commodity price changes.

To maintain and grow our production and cash flow, we must continue to develop existing reserves and locate or acquire new oil and gas reserves. Through our drilling programs and the acquisition of properties, we strive to maintain and grow our production and cash flow. However, as we produce from our properties, our reserves decline. We may be unable to find, develop or acquire additional reserves or production at an acceptable cost, if at all. In addition, these activities require substantial capital expenditures.

Actual quantities of oil and gas reserves and future cash flows from those reserves will most likely vary from our estimates. Estimating accumulations of oil and gas is complex. The process relies on interpretations of available geologic, geophysic, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires a number of economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

The proved and probable reserve information set forth in this report is based on estimates we prepared. Estimates prepared by others might differ materially from our estimates.

Actual quantities of oil and gas reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses will most likely vary from our estimates, with the variability likely to be higher for probable reserves estimates. In addition, the methodologies and evaluation techniques that we use, which include the use of multiple technologies, data sources and interpretation methods, may be different than those used by our competitors. Further, reserve estimates are subject to the evaluator s criteria and judgment and show important variability, particularly in the early stages of an oil and gas development. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of reserves to reflect production history, results of exploration and development activities and prevailing oil and gas prices. Our reserves also may be susceptible to drainage by operators on adjacent properties.

You should not assume that the present value of future net cash flows is the current market value of our proved oil and gas reserves. In accordance with new SEC requirements, we base the estimated discounted future net cash flows from proved reserves on the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials, and costs in effect at year-end. Actual

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future prices and costs may be materially higher or lower than the prices and costs we used. In addition, actual production rates for future periods may vary significantly from the rates assumed in the calculation.

There is limited refining capacity for our black wax crude oil, which may limit our ability to sell our current production or to increase our production at Monument Butte in the Uinta Basin. Most of the crude oil we produce in the Uinta Basin is known as black wax because it has higher paraffin content than crude oil found in most other major North American basins. Due to its wax content, it must remain heated during shipping, so the oil is transported by truck to refiners in the Salt Lake City area. We currently have agreements in place with area refiners that secure base load sales of substantially all of our expected production in the Uinta Basin through the end of 2010. In the current economic environment, there is a risk that they may fail to satisfy their obligations to us under those contracts. During the fourth quarter of 2008, the largest purchaser of our black wax crude oil failed to pay for certain deliveries of crude oil and filed for bankruptcy protection. Although we continue to sell our black wax crude oil to that purchaser on a short-term basis that provides for more timely cash payments, we cannot guarantee that we will be able to continue to sell to this purchaser or that similar substitute arrangements could be made for sales of our black wax crude oil with other purchasers if desired. An extended loss of our largest purchaser could have a material adverse effect on us because there are limited purchasers of our black wax crude. We continue to work with refiners to expand the market for our existing black wax crude oil production and to secure additional capacity to allow for production growth. However, without additional refining capacity, our ability to increase production from the field may be limited.

Lower oil and gas prices and other factors have resulted in ceiling test writedowns in the past and may in the future result in additional ceiling test writedowns or other impairments. We capitalize the costs to acquire, find and develop our oil and gas properties under the full cost accounting method. The net capitalized costs of our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. This is called a ceiling test writedown. As of December 31, 2008, we recorded a $1.8 billion ($1.1 billion after-tax) ceiling test writedown. We recorded an additional $1.3 billion ($854 million after-tax) ceiling test writedown as of March 31, 2009. Although a ceiling test writedown does not impact cash flow from operations, it does reduce our stockholders equity. Once recorded, a ceiling test writedown is not reversible at a later date even if oil and gas prices increase.

The risk that we will be required to further write down the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, writedowns may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. We may experience further ceiling test writedowns or other impairments in the future. In addition, any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

Drilling is a high-risk activity. In addition to the numerous operating risks described in more detail below, the drilling of wells involves the risk that no commercially productive oil or gas reservoirs will be encountered. In addition, we often are uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- adverse weather conditions and changes in weather patterns;
- unexpected drilling conditions;
- pressure or irregularities in formations;

embedded oilfield drilling and service tools;

equipment failures or accidents;

lack of necessary services or qualified personnel;

availability and timely issuance of required governmental permits and licenses;

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availability, costs and terms of contractual arrangements, such as leases, pipelines and related facilities to gather, process and compress, transport and market natural gas, crude oil and related commodities; and

compliance with, or changes in, environmental, tax and other laws and regulations.

The oil and gas business involves many operating risks that can cause substantial losses, and insurance may not protect us against all of these risks. We are not insured against all risks. Our oil and gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the risk of:

fires and explosions;

blow-outs;

uncontrollable or unknown flows of oil, gas, formation water or drilling fluids;

adverse weather conditions or natural disasters;

pipe or cement failures and casing collapses;

pipeline ruptures;

discharges of toxic gases;

build up of naturally occurring radioactive materials; and

vandalism.

If any of these events occur, we could incur substantial losses as a result of:

injury or loss of life;

severe damage or destruction of property and equipment, and oil and gas reservoirs;

pollution and other environmental damage;

investigatory and clean-up responsibilities;

regulatory investigation and penalties;

suspension of our operations; and

repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected.

Offshore and deepwater operations are subject to a variety of operating risks, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions have in the past, and may in the future,

cause substantial damage to facilities and interrupt production. Some of our offshore operations, and most of our deepwater and international operations, are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities that we do not own. Necessary infrastructures have been in the past, and may be in the future, temporarily unavailable due to adverse weather conditions or other reasons or may not be available to us in the future at all or on acceptable terms.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not insurable.

Exploration in deepwater involves significant financial risks, and we may be unable to obtain the drilling rigs or support services necessary for our deepwater drilling and development programs in a timely manner or at acceptable rates. Much of the deepwater play lacks the physical and oilfield service infrastructure necessary for production. As a result, development of a deepwater discovery may be a lengthy

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process and requires substantial capital investment, and it is difficult to estimate the timing of our production. Because of the size of significant projects in which we invest, we may not serve as the operator. As a result, we may have limited ability to exercise influence over operations related to these projects or their associated costs. Our dependence on the operator and other working interest owners for these deepwater projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital or lead to unexpected future losses.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business. In addition, potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include:

the amounts and types of substances and materials that may be released into the environment;

response to unexpected releases to the environment;

reports and permits concerning exploration, drilling, production and other operations;

the spacing of wells;

unitization and pooling of properties;

calculating royalties on oil and gas produced under federal and state leases; and

taxation.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs, natural resource damages and other environmental damages. We also could be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, changes to existing regulations or the adoption of new regulations may unfavorably impact us, our suppliers or our customers. For example, governments around the world have become increasingly focused on climate change matters. In the United States, legislation that directly impacts our industry has been proposed covering areas such as emission reporting and reductions, hydraulic fracturing, the repeal of certain oil and gas tax incentives and tax deductions, and the regulation of over-the-counter commodity hedging activities. These and other potential regulations could increase our costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows.

Congress has been actively considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which is now being considered by the U.S. Senate. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. Further, on April 2, 2007, the United States Supreme Court in Massachusetts,

et al. v. EPA, held that carbon dioxide may be regulated as an air pollutant under the federal Clean Air Act. On April 24, 2009, EPA responded to the Massachusetts, et al. v. EPA decision with a proposed finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change. EPA published the final version of this finding on December 15, 2009, which allowed EPA to proceed with the rulemaking process to regulate

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greenhouse gases under the Clean Air Act. In anticipation of the finalization of EPA s finding that greenhouse gases threaten public health and welfare, and that greenhouse gases from new motor vehicles contribute to climate change, EPA proposed a rule in September of 2009 that would require a reduction in emissions of greenhouse gases from motor vehicles and would trigger applicability of Clean Air Act permitting requirements for certain stationary sources of greenhouse gas emissions. In response to this issue, EPA also proposed a tailoring rule that would, in general, only impose greenhouse gas permitting requirements on facilities that emit more than 25,000 tons per year of greenhouse gases. Moreover, on September 22, 2009, EPA finalized a rule requiring nation-wide reporting of greenhouse gas emissions in 2011 for emissions occurring in 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year, and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control. The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. We deliver oil and gas through gathering systems and pipelines that we do not own. The lack of availability of capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through some firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, or may not be available to us in the future at a price that is acceptable to us. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

We have risks associated with our non-U.S. operations. Ownership of property interests and production operations in areas outside the United States is subject to the various risks inherent in international operations. These risks may include:

currency restrictions and exchange rate fluctuations;

loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection;

increases in taxes and governmental royalties;

forced renegotiation of, or unilateral changes to, or termination of contracts with governmental entities and quasi-governmental agencies;

changes in laws and policies governing operations of non-U.S. based companies;

our limited ability to influence or control the operation or future development of these non-operated properties;

the operator s expertise or other labor problems;

difficulties enforcing our rights against a governmental entity because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and

other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our international

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operations, we may be subject to the exclusive jurisdiction of non-U.S. courts or may not be successful in subjecting non-U.S. persons to the jurisdiction of the courts of the United States.

We may be subject to risks in connection with acquisitions. The successful acquisition of producing properties requires an assessment of several factors, including:

recoverable reserves;

future oil and gas prices and their appropriate differentials;

operating costs; and

potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections will not likely be performed on every well or facility, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems.

Competition for experienced technical personnel may negatively impact our operations or financial results. Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers and other professionals. Despite the recent decline in commodity prices and lower industry activity levels, competition for these professionals remains strong. We are likely to continue to experience increased costs to attract and retain these professionals.

There is competition for available oil and gas properties. Our competitors include major oil and gas companies, independent oil and gas companies and financial buyers. Some of our competitors may have greater and more diverse resources than we do. High commodity prices and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties.

Our certificate of incorporation, bylaws, some of our arrangements with employees and Delaware law contain provisions that could discourage an acquisition or change of control of our company. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to effect a change of control of our company, to acquire us or to replace incumbent management. In addition, our change of control severance plan and agreements, our omnibus stock plans and our incentive compensation plan contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of restricted stock, restricted stock units and stock options, upon a change of control. Section 203 of the Delaware General Corporation Law also imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions could discourage or prevent a change of control or reduce the price our stockholders receive in an acquisition of our company.

Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (1) claims from royalty owners for disputed royalty payments, (2) commercial disputes, (3) personal injury claims and (4) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

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

There were no matters submitted to a vote of our security holders during the fourth quarter of 2009.

Executive Officers of the Registrant

The following table sets forth the names of, ages (as of February 22, 2010) of and positions held by our executive officers. Our executive officers serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
Lee K. Boothby	48	President and Chief Executive Officer and Director	10
Gary D. Packer	47	Executive Vice President and Chief Operating Officer	14
Terry W. Rathert	57	Executive Vice President and Chief Financial Officer	20
Mona Leigh Bernhardt	43	Vice President Human Resources	10
W. Mark Blumenshine	51	Vice President Land	8
Stephen C. Campbell	41	Vice President Investor Relations	10
George T. Dunn	52	Vice President Mid-Continent	17
Daryll T. Howard	47	Vice President Rocky Mountains	13
John H. Jasek	40	Vice President Gulf of Mexico	10
Samuel E. Langford	52	Vice President Corporate Development	5
James J. Metcalf	52	Vice President Drilling	14
William D. Schneider	58	Vice President Onshore Gulf Coast and International	21
Michael D. Van Horn	58	Vice President Geoscience	3
James T. Zernell	52	Vice President Production	12
John D. Marziotti	46	General Counsel and Secretary	6
Brian L. Rickmers	41	Controller and Assistant Secretary	16
Susan G. Riggs	52	Treasurer	12

The executive officers have held the positions indicated above for the past five years, except as follows:

Lee K. Boothby was promoted to the position of President on February 5, 2009 and to the additional role of Chief Executive Officer on May 7, 2009. Our Board of Directors also has named Mr. Boothby to the additional role of Chairman of the Board, effective May 7, 2010 if he is re-elected as a director at our annual meeting on that date. Prior to February 5, 2009, Mr. Boothby served as Senior Vice President Acquisitions & Business Development since October 2007. He managed our Mid-Continent operations from February 2002 to October 2007, and was promoted from General Manager to Vice President in November 2004.

Gary D. Packer was promoted to the position of Executive Vice President and Chief Operating Officer on May 7, 2009. Prior thereto, he was promoted from Gulf of Mexico General Manager to Vice President Rocky Mountains in November 2004.

Terry W. Rathert was promoted from Senior Vice President to Executive Vice President on May 7, 2009 and previously was promoted from Vice President to Senior Vice President in November 2004. He also served as Secretary of our company until May 2008.

Mona Leigh Bernhardt was promoted from Manager to Vice President in December 2005.

W. Mark Blumenshine was promoted from Manager to Vice President in December 2005.

Stephen C. Campbell was promoted from Manager to Vice President in December 2005.

George T. Dunn was named Vice President Mid-Continent in October 2007. He managed our onshore Gulf Coast operations from 2001 to October 2007, and was promoted from General Manager to Vice President in November 2004.

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Daryll T. Howard was promoted to the position of Vice President Rocky Mountains on May 7, 2009. Mr. Howard joined Newfield in 1996. Prior to his promotion on May 7, 2009, Mr. Howard served as East Team Rocky Mountain Asset Manager since June 2008. Prior thereto, Mr. Howard assisted in establishing Newfield s Malaysia office and was instrumental in the success and growth of Newfield s international operations. Mr. Howard also previously held several positions of increasing breadth and responsibility in Newfield s Gulf of Mexico organization.

John H. Jasek was reappointed as Vice President Gulf of Mexico in December 2008. Prior to that, he served as Vice President Gulf Coast since October 2007 and became the manager of our onshore Gulf Coast operations at that time. He previously managed our Gulf of Mexico operations from March 2005 until October 2007, and was promoted from General Manager to Vice President in November 2006. Prior to March 2005, he was a Petroleum Engineer in the Western Gulf of Mexico.

Samuel E. Langford was promoted to the position of Vice President Corporate Development on May 7, 2009. Mr. Langford joined Newfield in 2004. Prior to his promotion on May 7, 2009, Mr. Langford served as Manager Acquisitions, Planning and Commercial Development of Newfield s Mid-Continent division since April 2004.

James J. Metcalf was promoted from Manager to Vice President in December 2005.

William D. Schneider was named Vice President Onshore Gulf Coast and International in December 2008. He has managed our international operations since May 2000.

Michael D. Van Horn joined our company as Senior Vice President Exploration in November 2006 and became our Vice President Geoscience on May 7, 2009. He served at EOG Resources, and its predecessor Enron Oil and Gas, from 1993 to November 2006. Most recently, he served as their Vice President of International Exploration. Prior to that position, he was Director of Exploration.

James T. Zernell was promoted from Manager to Vice President in December 2005.

John D. Marziotti was promoted to General Counsel in August 2007 and was named Secretary in May 2008. From November 2003, when he joined our company, until August 2007 he held the position of Legal Counsel. Prior to joining us, he was a shareholder of the law firm of Strasburger & Price, LLP.

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PART II

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

Market for Common Stock

Our common stock is listed on the New York Stock Exchange under the symbol NFX. The following table sets forth, for each of the periods indicated, the high and low reported sales price of our common stock on the NYSE.

	High	Low
2008:		
First Quarter	$ 57.75	$ 44.15
Second Quarter	69.77	51.88
Third Quarter	68.31	28.00
Fourth Quarter	31.28	15.45
2009:		
First Quarter	$ 26.50	$ 17.09
Second Quarter	38.74	21.65
Third Quarter	46.62	27.92
Fourth Quarter	51.27	39.26
2010:		
First Quarter (through February 22, 2010)	$ 54.07	$ 47.47

On February 22, 2010, the last reported sales price of our common stock on the NYSE was $49.34. As of that date, there were approximately 2,480 holders of record of our common stock.

Dividends

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indentures governing our 65/8% Senior Subordinated Notes due 2014 and 2016, our 71/8% Senior Subordinated Notes due 2018 and our 67/8% Senior Subordinated Notes due 2020 could restrict our ability to pay cash dividends. See Contractual Obligations under Item 7 of this report and Note 9, Debt, to our consolidated financial statements in Item 8 of this report.

Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2009.

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
October 1 October 31, 2009	1,897	$ 42.03		
November 1 November 30, 2009	8,961	42.41		
December 1 December 31, 2009	12,015	43.12		
Total	22,873	$ 42.75		

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock.

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Stockholder Return Performance Presentation

The performance presentation shown below is being furnished pursuant to applicable rules of the SEC. As required by these rules, the performance graph was prepared based upon the following assumptions:

- $100 was invested in our common stock, the S&P 500 Index, our prior peer group and our current peer group on December 31, 2004 at the closing price on such date;
- investment in each of our peer groups was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of the period; and
- dividends were reinvested on the relevant payment dates.

Prior Peer Group. Prior to 2009, our peer group consisted of Anadarko Petroleum Corporation, Apache Corporation, Bill Barrett Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, EOG Resources, Inc., Forest Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Pioneer Natural Resources Company, Range Resources Corporation, St. Mary Land & Exploration Company, Stone Energy Corporation, Swift Energy Company and XTO Energy Inc.

Current Peer Group. As part of its review of compensation during 2009, management and its compensation consultant reviewed the companies included in our peer group based on a variety of factors, including revenues, market capitalization, asset size, geographic location of assets and headquarters, culture and performance. As a result of this review, management adopted the current peer group. Our current peer group consists of Cabot Oil & Gas Corporation, Cimarex Energy Company, Denbury Resources Inc., EXCO Resources, Inc., Forest Oil Corporation, Noble Energy, Inc., Petrohawk Energy Corporation, Pioneer Natural Resources Company, Plains Exploration & Production Company, Range Resources Corporation, SandRidge Energy, Inc., Southwestern Energy Company and Ultra Petroleum Corp.

Total Return Analysis	**12/31/2004**	**12/31/2005**	**12/31/2006**	**12/31/2007**	**12/31/2008**	**12/31/2009**
Newfield Exploration Company	$ 100.00	$ 169.57	$ 155.60	$ 178.48	$ 66.88	$ 163.31
Prior Peer Group	$ 100.00	$ 154.45	$ 148.83	$ 222.27	$ 134.73	$ 199.77
Current Peer Group	$ 100.00	$ 170.09	$ 167.90	$ 252.64	$ 144.09	$ 232.61
S&P 500	$ 100.00	$ 104.89	$ 121.46	$ 128.13	$ 80.73	$ 102.08

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Item 6. ***Selected Financial Data***

SELECTED FIVE-YEAR FINANCIAL AND RESERVE DATA

The following table shows selected consolidated financial data derived from our consolidated financial statements and selected reserve data derived from our supplementary oil and gas disclosures set forth in Item 8 of this report. The data should be read in conjunction with Items 1 and 2, *Business and Properties* Proved and Probable Reserves and Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations,* of this report.

	Year Ended December 31,				
	2009[1]	**2008**	**2007**	**2006**	**2005**
	(In millions, except per share data)				
Income Statement Data:					
Oil and gas revenues	$ 1,338	$ 2,225	$ 1,783	$ 1,673	$ 1,762
Income (loss) from continuing operations	(542)	(373)	172	610	342
Net income (loss)	(542)	(373)	450	591	348
Earnings (loss) per share:					
Basic					
Income (loss) from continuing operations	(4.18)	(2.88)	1.35	4.82	2.73
Net income (loss)	(4.18)	(2.88)	3.52	4.67	2.78
Diluted					
Income (loss) from continuing operations	(4.18)	(2.88)	1.32	4.73	2.68
Net income (loss)	(4.18)	(2.88)	3.44	4.58	2.73
Weighted average number of shares outstanding for basic earnings per share	130	129	128	127	125
Weighted average number of shares outstanding for diluted earnings per share	130	129	131	129	128
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 1,578	$ 854	$ 1,166	$ 1,392	$ 1,119
Net cash used in continuing investing activities	(1,356)	(2,253)	(865)	(1,552)	(1,015)
Net cash provided by (used in) continuing financing activities	(168)	1,173	(117)	174	(124)
Balance Sheet Data (at end of period):					
Total assets	$ 6,254	$ 7,305	$ 6,986	$ 6,635	$ 5,081
Long-term debt	2,037	2,213	1,050	1,048	870
Proved Reserves Data (at end of period):					
Oil and condensate (MMBbls)	169	140	114	114	102
Gas (Bcf)	2,605	2,110	1,810	1,586	1,391
Total proved reserves (Bcfe)	3,616	2,950	2,496	2,272	2,001
Present value of estimated future after-tax net cash flows	$ 2,864	$ 2,929	$ 4,531	$ 3,447	$ 5,053

(1) Effective December 31, 2009, we adopted recently revised authoritative accounting and disclosure requirements for oil and gas reserves. As a result, these disclosures are not on a basis comparable to the prior years. Please see Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations* New

Accounting Requirements, of this report.

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

Overview

We are an independent oil and gas company engaged in the exploration, development and acquisition of oil and gas properties. Our domestic areas of operation include the Anadarko and Arkoma Basins of the Mid-Continent, the Rocky Mountains, onshore Texas and the Gulf of Mexico. Internationally, we are active in Malaysia and China.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and gas reserves. We use the full cost method of accounting for our oil and gas activities.

Oil and Gas Prices. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the amount of cash flow available for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of oil and gas that we can economically produce; and
- the accounting for our oil and gas activities including among other items, the determination of ceiling test writedowns.

Any extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. Please see the discussion under *Lower oil and gas prices and other factors have resulted in ceiling test writedowns in the past and may in the future result in additional ceiling test writedowns or other impairments* in Item 1A of this report and Liquidity and Capital Resources below.

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs.

Reserve Replacement. To maintain and grow our production and cash flow, we must continue to develop existing reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. Please see Proved Reserves below and Supplementary Financial Information Supplementary Oil and Gas Disclosures Estimated Net Quantities of Proved Oil and Gas Reserves in Item 8 of this report for the change in our total net proved reserves during the three-year period ended December 31, 2009. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves. See Items 1 and 2, *Business and Properties* Proved and Probable Reserves *Proved Reserves.*

Significant Estimates. We believe the most difficult, subjective or complex judgments and estimates we must make in connection with the preparation of our financial statements are:

- the quantity of our proved oil and gas reserves;

the timing of future drilling, development and abandonment activities;

the cost of these activities in the future;

the fair value of the assets and liabilities of acquired companies;

the fair value of our financial instruments including derivative positions; and

the fair value of stock-based compensation.

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Accounting for Hedging Activities. We do not designate price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2009, we had net derivative assets of $281 million, of which 57% was measured based upon our valuation model (i.e. Black Scholes) and, as such, is classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. Please see Critical Accounting Policies and Estimates *Commodity Derivative Activities* below and Note 5, Derivative Financial Instruments, and Note 8, Fair Value Measurements, to our consolidated financial statements in Item 8 of this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Results of Operations

Significant Events. We completed several significant transactions during 2008 and 2007 and recorded ceiling test writedowns under the full cost method of accounting at the end of 2008 and the first quarter of 2009, each of which affects the comparability of our results of operations and cash flows from period to period.

As of December 31, 2008, we recorded a $1.8 billion ceiling test writedown. We recorded an additional $1.3 billion ceiling test writedown as of March 31, 2009.

During the first six months of 2008, we entered into a series of transactions that had the effect of resetting all of our then outstanding crude oil hedges for 2009 and 2010. At the time of the reset, the mark-to-market value of these hedge contracts was a liability of $502 million and we paid an additional $56 million to purchase option contracts.

In October 2007, we sold all of our interests in the U.K. North Sea for $511 million in cash. The historical results of operations of our U.K. North Sea operations are reflected in our financial statements as discontinued operations. Except where noted, discussions in this report relate to continuing operations only.

In August 2007, we sold our shallow water Gulf of Mexico assets for $1.1 billion in cash and the purchaser s assumption of liabilities associated with future abandonment of wells and platforms.

In June 2007, we acquired Stone Energy Corporation s Rocky Mountain assets for $578 million in cash. Initially, we financed this acquisition through borrowings under our revolving credit agreement.

Please see Note 1, Organization and Summary of Significant Accounting Policies *Oil and Gas Properties*, Note 3, Discontinued Operations, Note 4, Oil and Gas Assets, and Note 5, Derivative Financial Instruments, to our consolidated financial statements appearing in Item 8 of this report for a discussion regarding these events.

Revenues. All of our revenues are derived from the sale of our oil and gas production. The effects of the settlement of hedges designated for hedge accounting are included in revenue, but those not so designated have no effect on our reported revenues. None of our outstanding oil and gas hedging contracts as of December 31, 2009 are designated for hedge accounting and the settlement of all hedging contracts during 2009 and 2008 had no effect on reported revenues. However, revenues for 2007 include losses on the settlement of hedging contracts designated for hedge accounting of $7 million. Please see Note 5, Derivative Financial Instruments, to our consolidated financial statements appearing in Item 8 of this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold. In addition, crude oil from our operations offshore Malaysia and China is produced into FPSOs and lifted and sold periodically as barge quantities are accumulated. Revenues are

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recorded when oil is lifted and sold, not when it is produced into the FPSO. As a result, the timing of liftings may impact period to period results.

Revenues of $1.3 billion for 2009 were 40% lower than 2008 revenues due to significantly lower average realized oil and gas prices partially offset by higher oil and gas production. Revenues of $2.2 billion for 2008 were 25% higher than 2007 revenues due to increased oil production and higher average realized prices for oil and gas partially offset by lower natural gas production.

	Year Ended December 31,		
	2009	2008	2007
Production[1]:			
Domestic:			
Natural gas (Bcf)	174.3	172.9	192.8
Oil and condensate (MBbls)	7,059	6,136	6,501
Total (Bcfe)	216.7	209.8	231.8
International:			
Natural gas (Bcf)			
Oil and condensate (MBbls)	6,120	4,439	2,258
Total (Bcfe)	36.7	26.6	13.5
Total:			
Natural gas (Bcf)	174.3	172.9	192.8
Oil and condensate (MBbls)	13,179	10,575	8,759
Total (Bcfe)	253.4	236.4	245.3
Average Realized Prices[2]:			
Domestic:			
Natural gas (per Mcf)	$ 3.48	$ 7.65	$ 6.33
Oil and condensate (per Bbl)	51.19	86.84	61.32
Natural gas equivalent (per Mcfe)	4.47	8.85	6.98
International:			
Natural gas (per Mcf)	$	$	$
Oil and condensate (per Bbl)	59.72	82.03	69.21
Natural gas equivalent (per Mcfe)	9.95	13.67	11.53
Total:			
Natural gas (per Mcf)	$ 3.48	$ 7.65	$ 6.33
Oil and condensate (per Bbl)	55.15	84.82	63.35
Natural gas equivalent (per Mcfe)	5.28	9.39	7.23

(1) Represents volumes lifted and sold regardless of when produced.

(2) Average realized prices only include the effects of hedging contracts that are designated for hedge accounting. Prior to the fourth quarter of 2005, we applied hedge accounting to qualifying derivatives, and the last of our previously designated cash flow hedges settled during 2007. Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been $6.42, $7.12 and $7.62 per Mcf for 2009, 2008 and 2007, respectively. Our total oil and condensate average realized price would have been $81.23, $69.13 and $55.04 per Bbl for 2009, 2008 and 2007, respectively. Without the effects of any hedging contracts designated for hedge accounting, our 2007 average realized prices would have been

$6.33 per Mcf for natural gas and $64.12 per Bbl for oil. All amounts for the year ended December 31, 2008 exclude the cash payments totaling $502 million to reset our 2009 and 2010 crude oil hedges.

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Domestic Production. Our 2009 domestic oil and gas production, stated on a natural gas equivalent basis, increased 3% over 2008 production primarily due to increased production in our Mid-Continent division as a result of continued successful drilling efforts, partially offset by natural field declines and the voluntary curtailment of approximately 3 Bcfe of production during the second half of 2009 from our Mid-Continent division due to low natural gas prices.

Our 2008 domestic oil and gas production, stated on a natural gas equivalent basis, decreased 9% from 2007 production, primarily as a result of the sale of our shallow water Gulf of Mexico assets in August 2007. In addition, 2008 production was negatively impacted by the deferral of approximately 5 Bcfe of production related to the 2008 hurricanes in the Gulf of Mexico. Production from our June 2007 acquisition of Stone Energy Corporation s Rocky Mountain assets partially offset the impact of the hurricanes. Without the impact of the Gulf of Mexico asset sale and the Rocky Mountain asset acquisition, our total 2008 oil and gas production increased 20% over 2007 due to increased production in our Mid-Continent and Rocky Mountain divisions as a result of continued successful drilling efforts.

International Production. Our 2009 international oil production, stated on a natural gas equivalent basis, increased 38% over 2008 production primarily due to new field developments on PM 318 and PM 323 in Malaysia and the timing of liftings from our oil production in Malaysia. Our 2008 international oil production increased 97% over 2007 production primarily due to new field developments on PM 323 in Malaysia.

Operating Expenses. We believe the most informative way to analyze changes in our operating expenses from period to period is on a unit-of-production, or per Mcfe, basis. However, because of the previously noted significant events during 2009, 2008 and 2007 and the year over year increases in our international production, period to period comparisons are difficult. For example, offshore Gulf of Mexico properties typically have significantly higher lease operating costs relative to onshore properties and offshore production is not subject to production taxes but onshore production is subject to these taxes.

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

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2009.

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2009	2008		2009	2008	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 0.94	$ 1.00	(6)%	$ 203	$ 210	(4)%
Production and other taxes	0.15	0.29	(48)%	33	60	(46)%
Depreciation, depletion and amortization	2.14	2.84	(25)%	463	597	(22)%
General and administrative	0.64	0.65	(2)%	139	136	2%
Ceiling test and other impairments	6.20	8.54	(27)%	1,344	1,792	(25)%
Other	0.03	0.02	50%	8	4	124%
Total operating expenses	10.10	13.34	(24)%	2,190	2,799	(22)%
International:						
Lease operating	$ 1.53	$ 2.05	(25)%	$ 56	$ 55	3%
Production and other taxes	0.82	3.64	(77)%	30	97	(69)%
Depreciation, depletion and amortization	3.39	3.77	(10)%	124	100	24%
General and administrative	0.14	0.18	(22)%	5	5	12%
Ceiling test writedown		2.66	(100)%		71	(100)%
Total operating expenses	5.88	12.30	(52)%	215	328	(34)%
Total:						
Lease operating	$ 1.02	$ 1.12	(9)%	$ 259	$ 265	(2)%
Production and other taxes	0.25	0.66	(62)%	63	157	(60)%
Depreciation, depletion and amortization	2.32	2.95	(21)%	587	697	(16)%
General and administrative	0.57	0.60	(5)%	144	141	2%
Ceiling test and other impairments	5.30	7.88	(33)%	1,344	1,863	(28)%
Other	0.03	0.01	200%	8	4	124%
Total operating expenses	9.49	13.22	(28)%	2,405	3,127	(23)%

Domestic Operations. Our domestic operating expenses for 2009, stated on a Mcfe basis, decreased 24% over 2008 primarily due to the goodwill impairment charge recorded at December 31, 2008 and the magnitude of the full cost ceiling test writedowns recorded at December 31, 2008 and March 31, 2009. The components of the period to period change are as follows:

Lease operating expense (LOE) decreased 6% per Mcfe due to lower overall operating and service costs and the 3% increase in production volumes period over period.

Production and other taxes decreased 48% per Mcfe due to significantly lower realized commodity prices period over period. We received refunds of $24 million ($0.11 per Mcfe) during 2009 related to production tax exemptions on some of our onshore wells, whereas we received similar refunds of $35 million ($0.17 per Mcfe) during 2008.

Our depreciation, depletion and amortization (DD&A) rate decreased 25% per Mcfe primarily as a result of the ceiling test writedowns recorded at December 31, 2008 and March 31, 2009.

General and administrative (G&A) expense per Mcfe decreased 2% period over period while total G&A expense increased slightly. The decrease per Mcfe is primarily due to the 3% increase in production volumes period over period. The slight increase in total G&A is primarily due to increased employee-related expenses associated with our growing domestic workforce offset by a decrease in incentive compensation expense, which is calculated based on adjusted net income (as defined in our incentive

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compensation plan). Adjusted net income for purposes of our incentive compensation plan excluded (a) unrealized gains and losses on commodity derivatives and (b) the impact from any full cost ceiling test writedowns. Additionally, we match the costs/benefits of the 2008 crude oil hedge unwind/reset with the period in which these barrels are produced for the purposes of determining adjusted net income. During 2009, we capitalized $58 million ($0.27 per Mcfe) of direct internal costs as compared to $49 million ($0.23 per Mcfe) in 2008.

In 2009, we recorded a ceiling test writedown of $1.3 billion ($6.20 per Mcfe) due to significantly lower natural gas prices at March 31, 2009. In 2008, we recorded a ceiling test writedown of $1.7 billion ($8.25 per Mcfe) due to significantly lower oil and gas commodity prices at year-end 2008. In 2008, we also recorded a goodwill impairment charge of $62 million ($0.29 per Mcfe) due to the significant decline in oil and gas commodity prices and the decline in our market capitalization at that time.

Other expenses for 2009 primarily includes long-term rig contract termination fees resulting from our decision to limit our 2009 capital expenditures to a level that we expected to be funded with cash flows from operations. Other expenses for 2008 includes the reversal of a portion of accrued business interruption insurance claims related to 2005 Hurricane Ivan which were determined during 2008 to be uncollectible.

International Operations. Our international operating expenses for 2009, stated on a Mcfe basis, decreased 52% over the same period of 2008 primarily due to the 2008 full cost ceiling test writedown in Malaysia and significantly higher production taxes during 2008 due to substantially higher oil prices. The components of the period to period change are as follows:

LOE decreased 25% per Mcfe while total LOE increased slightly over 2008. The decrease in LOE per Mcfe is primarily due to increased production volumes associated with the new field developments on PM 318 and PM 323 in Malaysia and lower overall operating and service costs.

Production and other taxes decreased significantly due to substantially lower realized oil prices during 2009.

Total DD&A expense increased 24% primarily due to additional production volumes and the timing of liftings of these volumes associated with new field developments on PM 318 and PM 323 in Malaysia, partially offset by a decrease in the DD&A rate resulting from the 2008 Malaysia ceiling test writedown.

G&A expense decreased 22% per Mcfe primarily due to the 38% increase in production volumes in 2009.

In 2008, we recorded a ceiling test writedown of $71 million associated with our operations in Malaysia due to significantly lower oil prices at year-end 2008.

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

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2008.

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2008	2007		2008	2007	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 1.00	$ 1.21	(17)%	$ 210	$ 281	(25)%
Production and other taxes	0.29	0.31	(6)%	60	73	(17)%
Depreciation, depletion and amortization	2.84	2.78	2%	597	643	(7)%
General and administrative	0.65	0.65		136	150	(9)%
Ceiling test and other impairments	8.54		100%	1,792		100%
Other	0.02		100%	4		100%
Total operating expenses	13.34	4.95	169%	2,799	1,147	144%
International:						
Lease operating	$ 2.05	$ 2.41	(15)%	$ 55	$ 33	68%
Production and other taxes	3.64	2.10	73%	97	28	241%
Depreciation, depletion and amortization	3.77	2.85	32%	100	39	160%
General and administrative	0.18	0.35	(49)%	5	5	(2)%
Ceiling test writedown	2.66		100%	71		100%
Total operating expenses	12.30	7.71	60%	328	105	214%
Total:						
Lease operating	$ 1.12	$ 1.28	(13)%	$ 265	$ 314	(15)%
Production and other taxes	0.66	0.41	61%	157	101	56%
Depreciation, depletion and amortization	2.95	2.78	6%	697	682	2%
General and administrative	0.60	0.63	(5)%	141	155	(9)%
Ceiling test writedown	7.88		100%	1,863		100%
Other	0.01		100%	4		100%
Total operating expenses	13.22	5.10	159%	3,127	1,252	150%

Domestic Operations. Our domestic operating expenses for 2008, stated on a Mcfe basis, increased 169% over 2007 due primarily to a 2008 full cost ceiling test writedown and goodwill impairment charge. The components of the period to period change are as follows:

LOE decreased 17% per Mcfe due to the sale of our shallow water Gulf of Mexico properties in August 2007, which had relatively high LOE per Mcfe. Our 2007 LOE was adversely impacted by repair expenditures of

$52 million ($0.22 per Mcfe) related to the 2005 storms. Without the impact of the repair expenditures related to the 2005 storms, our 2007 LOE would have been $0.99 per Mcfe. The decrease in LOE was partially offset by higher operating costs in 2008 for all our operations.

Production and other taxes decreased 6% per Mcfe due to refunds of $35 million ($0.17 per Mcfe) related to production tax exemptions on some of our onshore wells recorded during 2008 compared to refunds of $8 million ($0.04 per Mcfe) recorded during 2007. The benefit of the refunds was partially offset by increased commodity prices and increased production from our Mid-Continent and Rocky Mountain operations, which are subject to production taxes, and the sale of our Gulf of Mexico properties, which were not subject to production taxes.

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Our DD&A rate increased 2% per Mcfe while total DD&A expense decreased 7% period over period primarily due to the sale of our Gulf of Mexico properties in August 2007. The increase in the DD&A rate per Mcfe was due to higher cost reserve additions. This increase was partially offset by a decrease in accretion expense due to the significant reduction in our asset retirement obligation following the sale of our Gulf of Mexico properties.

G&A expense per Mcfe remained flat period over period while total G&A expense decreased 9% over 2007. The decrease in total G&A expense was primarily due to a 2007 litigation settlement reserve associated with a statewide royalty owner class action lawsuit in Oklahoma which was partially offset by increased employee related expenses in 2008 due to our increased domestic workforce. During 2008, we capitalized $49 million ($0.23 per Mcfe) of direct internal costs as compared to $49 million ($0.21 per Mcfe) in 2007.

In 2008, we recorded a ceiling test writedown of $1.7 billion ($8.25 per Mcfe) due to significantly lower oil and gas commodity prices at year-end 2008. We also recorded a goodwill impairment charge of $62 million ($0.29 per Mcfe) due to the significant decline in oil and gas commodity prices and the decline in our market capitalization at that time.

Other expenses for 2008 includes the reversal of a portion of accrued business interruption insurance claims related to 2005 Hurricane Ivan which were determined during 2008 to be uncollectible.

International Operations. Our international operating expenses for 2008, stated on a Mcfe basis, increased 60% over the same period of 2007 primarily due to higher production taxes and a full cost ceiling test writedown in Malaysia. The components of the period to period change are as follows:

LOE decreased 15% per Mcfe while total LOE increased 68% over 2007. The decrease on a per unit basis resulted from increased liftings in Malaysia. The increase in total LOE was primarily due to new field developments on PM 318 and PM 323 and higher operating costs in Malaysia.

Production and other taxes increased significantly in 2008 due to an increase in the tax rate per unit for our oil lifted and sold in Malaysia as a result of substantially higher oil prices during 2008.

The DD&A rate in 2008 increased as a result of higher cost reserve additions in Malaysia.

G&A expense decreased 49% per Mcfe primarily due to increased production in Malaysia during 2008.

In 2008, we recorded a ceiling test writedown of $71 million associated with our operations in Malaysia due to significantly lower oil prices at year-end 2008.

Interest Expense. The following table presents information about interest expense for each of the years in the three-year period ended December 31, 2009.

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Gross interest expense:			
Credit arrangements	$ 8	$ 10	$ 14
Senior notes	12	13	23

Senior subordinated notes	102	87	59
Other	4	2	6
Total gross interest expense	126	112	102
Capitalized interest	(51)	(60)	(47)
Net interest expense	$ 75	$ 52	$ 55

The increase in gross interest expense in 2009 as compared to 2008, and 2008 as compared to 2007, resulted primarily from the May 2008 issuance of $600 million principal amount of our 71/8% Senior

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Subordinated Notes due 2018. In October 2007, we repaid $125 million principal amount of our 7.45% Senior Notes.

We capitalize interest with respect to our unproved properties. Capitalized interest during 2009 decreased as compared to 2008 due to a reduction in our unproved property base resulting from the evaluation of such leasehold acreage. Interest capitalized during 2008 increased over 2007 due to an increase in our unproved property base primarily as a result of the Rocky Mountain asset acquisition in June 2007.

Commodity Derivative Income (Expense). The significant fluctuation in commodity derivative income (expense) from year to year is due to the extreme volatility of oil and gas prices and changes in our outstanding hedging contracts during these years.

Taxes. The effective tax rates for the years ended December 31, 2009, 2008 and 2007 were 39%, 30% and 41%, respectively. Our effective tax rate was different than the federal statutory tax rate for all three years primarily due to deductions that do not generate tax benefits, state income taxes and the differences between international and U.S. federal statutory rates. Our effective tax rate for 2009 increased because we released the valuation allowance related to the tax benefit associated with the Malaysia ceiling test writedown recorded in the fourth quarter of 2008. Our effective tax rate for 2008 decreased from 2007 because during 2008 we were not able to recognize the full tax benefit associated with the $71 million ceiling test writedown in Malaysia and the $62 million goodwill impairment charge did not generate a tax benefit.

Estimates of future taxable income can be significantly affected by changes in oil and gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

Liquidity and Capital Resources

We must find new and develop existing reserves to maintain and grow our production and cash flow. We accomplish this through successful drilling programs and the acquisition of properties. These activities require substantial capital expenditures. Lower prices for oil and gas may reduce the amount of oil and gas that we can economically produce, and can also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital, as further described below.

We establish a capital budget at the beginning of each calendar year. Our 2010 capital budget is $1.6 billion and focuses on projects we believe will generate and lay the foundation for production growth. Our 2010 capital budget (excluding acquisitions) is guided by our anticipated 2010 cash flows.

Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

On January 25, 2010, we sold $700 million of 67/8% Senior Subordinated Notes due 2020 and received net proceeds of $686 million. These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility, $215 million to fund the acquisition of assets from TXCO Resources Inc. and we tendered for approximately $143 million of our outstanding 75/8% Senior Notes due 2011.

We continue to hold auction rate securities with a fair value of $40 million. We attempt to sell these securities every 7-28 days until the auctions succeed, the issuer calls the securities or the securities mature. We currently do not believe that the decrease in the fair value of these investments is permanent nor that the failure of the auction mechanism will have a material impact on our liquidity given the amount of our available borrowing capacity under our credit arrangements. See Note 8, Fair Value Measurements, to our consolidated financial statements for more information regarding the auction rate securities.

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Credit Arrangements. We have a revolving credit facility that matures in June 2012 and provides for loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank as agent. As of December 31, 2009, the largest commitment was 16% of total commitments. However, the amount that we can borrow under the facility could be limited by changing expectations of future oil and gas prices because the maximum amount that we may borrow under the facility is determined by our lenders annually each May (and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures) using a process that takes into account the value of our estimated reserves and hedge position and the lenders commodity price assumptions.

In the future, total commitments under the facility could be increased to a maximum of $1.65 billion if the existing lenders increase their individual loan commitments or new financial institutions are added to the facility. We do not believe we could access such additional capacity in the current credit market. In addition, subject to compliance with covenants in our credit facility that restrict our ability to incur additional debt, we also have a total of $120 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions. For a more detailed description of the terms of our credit arrangements, please see Note 9, Debt , to our consolidated financial statements appearing in Item 8 of this report.

At February 22, 2010, we had $1 million of undrawn letters of credit and outstanding borrowings of $75 million under our $1.25 billion credit facility. Our available borrowing capacity under our credit arrangements was approximately $1.3 billion as of February 22, 2010.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. Although we anticipate that our 2010 capital spending (excluding acquisitions) will correspond with our anticipated 2010 cash flows, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

At December 31, 2009, we had positive working capital of $20 million. The decrease in our working capital balance as compared to December 31, 2008 is primarily due to a $396 million decrease in net derivative assets and their related deferred taxes resulting from the settlement of contracts during 2009, partially offset by the timing of receivable collections from purchasers, payments made by us to vendors and other operators, and the timing and amount of advances received from our joint operations.

At December 31, 2008, we had positive working capital of $121 million. During 2008, we used $271 million of cash and short-term investments on hand at the beginning of 2008 to fund a portion of our capital program and reclassified $75 million of our auction rate securities from short-term to long-term investments. In addition, at December 31, 2008, we had a net derivative asset of $663 million compared to a net derivative liability of $84 million at December 31, 2007. These working capital increases were partially offset by a change in our net current deferred tax position. Our net current deferred tax position was a liability of $226 million at December 31, 2008 compared to an asset of $35 million at December 31, 2007.

Cash Flows from Operations. Cash flows from operations (both continuing and discontinued) are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital. We sell substantially all of our oil and gas production under floating price market sensitive contracts. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months. See Oil and Gas Hedging below.

We typically receive the cash associated with oil and gas sales within 45-60 days of production. As a result, cash flows from operations and income from operations generally correlate, but cash flows from operations are impacted by changes in working capital and are not affected by DD&A, ceiling test writedowns, other impairments, or other non-cash charges or credits.

Our net cash flow from operations was $1.6 billion in 2009, an increase of 85% compared to net cash flow from operations of $854 million in 2008. This increase is primarily due to cash receipts related to

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derivative settlements of $883 million during 2009 compared to cash payments of $750 million during 2008. The cash payments in 2008 included $558 million to reset our 2009 and 2010 crude oil hedging contracts effectively settling the liability on our balance sheet at that time. Our 2009 net cash flows from operations were negatively impacted by lower average realized commodity prices during the year. Our working capital requirements during 2009 increased compared to 2008 as a result of the timing of drilling activities, receivable collections from purchasers, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Our net cash flow from operations was $854 million in 2008, a decrease of 26% compared to net cash flow from operations of $1.2 billion in 2007. This decrease is primarily due to the $558 million paid in 2008 to reset our 2009 and 2010 crude oil hedging contracts. Even though our 2008 production volumes were impacted by our 2007 property sales, the impact of this transaction on net cash flows from operations was somewhat offset by higher average realized commodity prices during 2008, increased production from our Mid-Continent and Rocky Mountain divisions and increased liftings in Malaysia. Our working capital requirements during 2008 decreased compared to 2007 as a result of the timing of drilling activities, receivable collections from purchasers, payments made by us to vendors and other operators, and the timing and amount of advances received from our joint operations.

Cash Flows from Investing Activities. Net cash used in investing activities for 2009 was $1.4 billion compared to $2.3 billion for 2008.

During 2009, we:

- spent $1.4 billion (including $9 million for acquisitions of oil and gas properties);
- received proceeds of $33 million from sales of oil and gas properties; and
- redeemed investments of $20 million.

During 2008, we:

- spent $2.3 billion (including $223 million for acquisitions of oil and gas properties); and
- purchased investments of $22 million and redeemed investments of $70 million.

Capital Expenditures. Our capital spending of $1.4 billion for 2009 decreased 38% from our $2.3 billion of capital spending during 2008. These amounts exclude recorded asset retirement obligations of $19 million in 2009 and $15 million in 2008. Of the $1.4 billion spent in 2009, we invested $937 million in domestic exploitation and development, $181 million in domestic exploration (exclusive of exploitation and leasehold activity), $147 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $148 million outside the United States.

Our capital spending of $2.3 billion for 2008 decreased 13% from our $2.6 billion of capital spending during 2007. These amounts exclude recorded asset retirement obligations of $15 million in 2008 and $21 million in 2007. Of the $2.3 billion spent in 2008, we invested $1.3 billion in domestic exploitation and development, $352 million in domestic exploration (exclusive of exploitation and leasehold activity), $363 million in acquisitions (includes the acquisition of properties in South Texas) and domestic leasing activity and $225 million outside the United States.

We have budgeted $1.6 billion for capital spending in 2010, including $124 million of estimated capitalized interest and overhead. Approximately 40% of the $1.6 billion is initially allocated to the Mid-Continent, 23% to the Rocky Mountains, 14% to the Gulf of Mexico, 10% to onshore Texas, and 13% to international projects. See Items 1 and 2,

Business and Properties Our Properties and Plans for 2010. The 2010 capital budget is based on our expectation that we will live within anticipated cash flow from operations (excluding acquisitions). Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

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Cash Flows from Financing Activities. Net cash used in financing activities for 2009 was $168 million compared to $1.2 billion of net cash provided by financing activities for 2008.

During 2009, we:

borrowed $1.0 billion and repaid $1.2 billion under our credit arrangements; and

received proceeds of $9 million from the issuance of shares of our common stock upon the exercise of stock options.

During 2008, we:

borrowed $2.6 billion and repaid $2.0 billion under our credit arrangements;

issued $600 million aggregate principal amount of our 71/8% Senior Subordinated Notes due 2018 and paid $8 million in associated debt issue costs; and

received proceeds of $20 million from the issuance of shares of our common stock upon the exercise of stock options.

Proved Reserves

To maintain and grow our production and cash flow, we must continue to develop existing proved reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. The following is a discussion of proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	2009	2008	2007
		(Bcfe)	
Proved Reserves:			
Beginning of year	2,950	2,496	2,272
Reserve additions	1,342	758	881
Reserve revisions	(384)	(67)	(12)
Sales	(35)	(2)	(396)
Production	(257)	(235)	(249)
End of year	3,616	2,950	2,496
Proved Developed Reserves:			
Beginning of year	1,827	1,566	1,484
End of year	1,908	1,827	1,566

Our proved natural gas reserves at year-end 2009 were 2.6 Tcf compared to 2.1 Tcf at year-end 2008 and 1.8 Tcf at year-end 2007. Our proved crude oil and condensate reserves at year-end 2009 were 169 million barrels compared to 140 million barrels at year-end 2008 and 114 million barrels at year-end 2007. Natural gas comprised about 72%, 72% and 73% of our proved reserves at year-end 2009, 2008 and 2007, respectively.

Reserve Additions and Revisions. During 2009, we added 958 Bcfe net proved reserves as a result of additions (extensions, discoveries, improved recovery and purchases of reserves in place) and revisions, as described below. Of this amount, 693 Bcfe of proved undeveloped reserves primarily associated with our Woodford Shale and Monument Butte fields was the result of the changes in SEC reserves reporting rules expanding proved undeveloped reserves beyond one offset to a proved developed location. We expect the majority of future reserve additions to be associated with infill drilling, extensions of current fields and new discoveries, as well as improved recovery operations and purchases of proved properties. The success of these operations will directly impact reserve additions or revisions in the future.

Additions. We added 1,342 Bcfe proved reserves during 2009, approximately 521 Bcfe of which were the result of successful development drilling in our Mid-Continent and Rocky Mountain business units. During 2008, we added 758 Bcfe of proved reserves, approximately 599 Bcfe of which were as a result of successful drilling efforts in the Mid-Continent and Rocky Mountains. During 2007, we added 881 Bcfe of proved reserves. Of this amount, 519 Bcfe was related to successful development drilling in our Mid-Continent and

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Onshore Gulf Coast business units and approximately 198 Bcfe was related to our purchase of reserves in place primarily associated with the acquisition of Stone Energy s Rocky Mountain assets in June 2007.

Revisions. Total revisions in 2009 were a negative 384 Bcfe, or 13% of the beginning of year reserve base. The revisions included a negative price revision of 259 Bcfe primarily related to our onshore natural gas plays, such as the Woodford Shale, and were primarily proven undeveloped reserves. The remaining 125 Bcfe of revisions in 2009 were negative performance revisions and were principally proved developed producing reserve revisions. Total revisions for 2008 were a negative 67 Bcfe and were primarily price-related domestic revisions associated with the decrease in both oil and gas prices from 2007 to 2008. Total revisions for 2007 were a negative 12 Bcfe and were primarily performance revisions associated with our Onshore Gulf Coast properties.

Sales. During 2009, we sold approximately 35 Bcfe of reserves associated with our domestic operations. In 2008, sales of reserves were negligible. Substantially all the 396 Bcfe of sales of oil and gas reserves during 2007 were related to our shallow water Gulf of Mexico assets and our coal bed methane assets in the Cherokee Basin of Oklahoma.

Future Net Cash Flows. At December 31, 2009, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $2.9 billion (stated in accordance with the regulations of the SEC and the Financial Accounting Standards Board (FASB)). This present value was calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves. This amount is unchanged from the $2.9 billion at December 31, 2008 despite lower natural gas prices utilized to calculate 2009 proved reserves. Reserve quantity additions as a result of our drilling success during 2009 coupled with the additional reserve quantities recognized as a result of the SEC s new reserves rules offset the impact of the lower natural gas prices utilized to calculate 2009 proved reserves. The decrease of $1.6 billion, or 35%, in 2008 compared to 2007 is primarily due to lower commodity prices at year-end 2008. See *Supplementary Financial Information* Supplementary Oil and Gas Disclosures Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves under Item 8 of this report.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money to the evaluating party and the perceived risks inherent in producing oil and gas.

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Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of December 31, 2009.

	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
Revolving credit facility	$ 384	$	$ 384	$	$
75/8% Senior Notes due 2011	175		175		
65/8% Senior Subordinated Notes due 2014	325			325	
65/8% Senior Subordinated Notes due 2016	550				550
71/8% Senior Subordinated Notes due 2018	600				600
Total debt	2,034		559	325	1,150
Other obligations:					
Interest payments[1]	738	118	215	201	204
Net derivative liabilities (assets)	(281)	(267)	(14)		
Asset retirement obligations	92	10	13	9	60
Operating leases	127	63	20	18	26
Deferred acquisition payments	2	2			
Firm transportation	233	31	59	58	85
Oil and gas activities[2]	508				
Total other obligations	1,419	(43)	293	286	375