NEWFIELD EXPLORATION CO /DE/
Form 10-Q
July 24, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended June 30, 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 (State or other jurisdiction of incorporation or organization)	72-1133047 (I.R.S. Employer Identification Number)

363 North Sam Houston Parkway East
Suite 100
Houston, Texas 77060
(Address and Zip Code of principal executive offices)

(281) 847-6000
(Registrant’s telephone number, including area code)

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

(§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark 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

As of July 23, 2009, there were 132,657,722 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEET
(In millions, except share data)
(Unaudited)

	June 30, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$38	$24
Accounts receivable	290	375
Inventories	128	96
Derivative assets	549	663
Other current assets	75	48
Total current assets	1,080	1,206
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,218 at June 30, 2009 and $1,303 at December 31, 2008 were excluded from amortization)	9,676	10,349
Less—accumulated depreciation, depletion and amortization	(4,887)	(4,591)
Total property and equipment, net	4,789	5,758
Derivative assets	101	247
Long-term investments	59	72
Deferred taxes	9	¾
Other assets	20	22
Total assets	$6,058	$7,305
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$79	$103
Accrued liabilities	495	672
Advances from joint owners	54	73
Asset retirement obligation	5	11
Deferred taxes	185	226
Total current liabilities	818	1,085
Other liabilities	39	22
Long-term debt	2,292	2,213
Asset retirement obligation	74	70
Deferred taxes	288	658
Total long-term liabilities	2,693	2,963
Commitments and contingencies (Note 5)	¾	¾
Stockholders' equity:		
Preferred stock ($0.01 par value; 5,000,000 shares authorized; no shares issued)	¾	¾
Common stock ($0.01 par value; 200,000,000 shares authorized at June 30, 2009 and December 31, 2008;	1	1

134,117,650 and 133,985,751 shares issued at June 30, 2009 and December 31, 2008, respectively)		
Additional paid-in capital	1,359	1,335
Treasury stock (at cost; 1,470,186 and 1,908,243 shares at June 30, 2009 and December 31, 2008, respectively)	(33)	(32)
Accumulated other comprehensive income (loss):		
Unrealized loss on investments	(13)	(13)
Unrealized gain on pension assets	2	2
Retained earnings	1,231	1,964
Total stockholders' equity	2,547	3,257
Total liabilities and stockholders' equity	$6,058	$7,305

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF INCOME
(In millions, except per share data)
(Unaudited)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Oil and gas revenues	$287	$691	$549	$1,207
Operating expenses:				
Lease operating	57	58	128	117
Production and other taxes	15	52	24	103
Depreciation, depletion and amortization	137	166	296	323
General and administrative	34	37	66	69
Ceiling test writedown	¾	¾	1,344	¾
Other	5	¾	7	¾
Total operating expenses	248	313	1,865	612
Income (loss) from operations	39	378	(1,316)	595
Other income (expenses):				
Interest expense	(32)	(28)	(64)	(47)
Capitalized interest	12	13	26	27
Commodity derivative income (expense)	(81)	(652)	197	(973)
Other	2	¾	5	2
Total other income (expenses)	(99)	(667)	164	(991)
Loss before income taxes	(60)	(289)	(1,152)	(396)
Income tax provision (benefit):				
Current	(4)	5	1	25
Deferred	(17)	(50)	(420)	(113)
Total income tax benefit	(21)	(45)	(419)	(88)
Net loss	$(39)	$(244)	$(733)	$(308)
Loss per share:				
Basic	$(0.30)	$(1.89)	$(5.66)	$(2.39)
Diluted	$(0.30)	$(1.89)	$(5.66)	$(2.39)
Weighted average number of shares outstanding for basic loss per share	130	129	129	129
Weighted average number of shares outstanding for diluted loss per share	130	129	129	129

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)
(Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash flows from operating activities:		
Net loss	$(733)	$(308)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	296	323
Deferred tax benefit	(420)	(113)
Stock-based compensation	15	12
Ceiling test writedown	1,344	
Commodity derivative (income) expense	(197)	973
Cash receipts (payments) on derivative settlements	459	(668)
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	85	(85)
(Increase) decrease in inventories	(30)	4
Increase in commodity derivative assets		(63)
Increase in other current assets	(41)	(30)
Decrease in other assets	14	1
Increase (decrease) in accounts payable and accrued liabilities	(78)	97
Increase (decrease) in advances from joint owners	(19)	14
Increase in other liabilities	17	15
Net cash provided by operating activities	712	172
Cash flows from investing activities:		
Additions to oil and gas properties	(778)	(1,072)
Acquisition of oil and gas properties	(9)	(231)
Purchase price adjustment related to sale of oil and gas properties		(10)
Additions to furniture, fixtures and equipment	(3)	(7)
Purchases of investments		(22)
Redemptions of investments	14	70
Net cash used in investing activities	(776)	(1,272)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	732	1,226
Repayments of borrowings under credit arrangements	(654)	(958)
Net proceeds from issuance of senior subordinated notes		592
Proceeds from issuances of common stock	1	18
Purchase of treasury stock, net	(1)	
Net cash provided by financing activities	78	878
Increase (decrease) in cash and cash equivalents	14	(222)
Cash and cash equivalents, beginning of period	24	250
Cash and cash equivalents, end of period	$38	$28

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive Income (Loss)	Total Stockholders'
	Shares	Amount	Shares	Amount	Capital	Earnings		Equity
Balance, December 31, 2008	134.0	$ 1	(1.9)	$ (32)	$ 1,335	$ 1,964	$ (11)	$ 3,257
Issuances of common and restricted stock	0.1				1			1
Treasury stock, at cost			0.4	(1)				(1)
Stock-based compensation					23			23
Comprehensive income (loss):								
Net loss						(733)		(733)
Total comprehensive loss								(733)
Balance, June 30, 2009	134.1	$ 1	(1.5)	$ (33)	$ 1,359	$ 1,231	$ (11)	$ 2,547

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent oil and gas company engaged in the exploration, development and acquisition of natural gas and crude oil 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 financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to “Newfield,” “we,” “us” or “our” are to Newfield Exploration Company and its subsidiaries.

These unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to state fairly our financial position as of, and results of operations for, the periods presented. These financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America. Interim period results are not necessarily indicative of results of operations or cash flows for a full year.

These financial statements and notes should be read in conjunction with our audited consolidated financial statements and the notes thereto included in our annual report on Form 10-K for the year ended December 31, 2008.

Dependence on Oil and Natural Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil and natural gas. Historically, the energy markets have been very volatile, and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. An extended decline in oil or natural gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and natural gas reserves that we can economically produce.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil and gas reserves. Actual results could differ from these estimates. Our most significant financial estimates are associated with our estimated proved oil and gas reserves.

Investments

Investments consist primarily of debt and equity securities as well as auction rate securities, substantially all of which are classified as “available-for-sale” and stated at fair value. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component of stockholders’ equity. Realized gains or losses are computed based on specific identification of the securities sold. We realized interest income and gains on our investments for the three months ended June 30, 2009 and 2008 of $0.5 million and $1 million, respectively, and for the six months ended June 30, 2009 and 2008 of $2 million and $3 million, respectively.

Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Crude oil from our operations offshore Malaysia and China is produced into floating production, storage and off-loading vessels and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 660,000 barrels and 293,000 barrels of crude oil valued at cost of $19 million and $9 million at June 30, 2009 and December 31, 2008, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depreciation, depletion and amortization expense.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis.

Capitalized costs and estimated future development and abandonment costs are amortized on a unit-of-production method based on proved reserves associated with the applicable cost center. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling. A particular cost center ceiling is equal to the sum of:

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using end of period oil and natural gas prices applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus

- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less

- related income tax effects.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized.

If net capitalized costs of oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown reduces earnings and stockholders' equity in the period of occurrence and, holding other factors constant, results in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and natural gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. During the first quarter of 2009, natural gas prices decreased significantly as compared to prices in effect at December 31, 2008. At March 31, 2009, the ceiling value of our reserves was calculated based upon quoted market prices of $3.63 per MMBtu for natural gas and $49.65 per barrel for oil, adjusted for market differentials. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties at March 31, 2009 exceeded the ceiling amount by approximately $1.3 billion ($854 million, after-tax). At June 30, 2009, the cost center ceilings with respect to our properties in the U.S., Malaysia and China exceeded the net capitalized costs of the respective properties. As such, no ceiling test writedowns were required.

A decline of oil and natural gas prices subsequent to June 30, 2009 could result in additional ceiling test writedowns in the third quarter of 2009 and possibly thereafter.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Accounting for Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the present value of the asset retirement cost in oil and gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included as depreciation, depletion and amortization expense on our consolidated statement of income.

The changes to our ARO for the six months ended June 30, 2009 are set forth below (in millions):

Balance as of January 1, 2009	$81
Accretion expense	3
Additions	4
Settlements	(9)
Balance at June 30, 2009	$79
Less: Current portion of ARO at June 30, 2009	(5)
Total long-term ARO at June 30, 2009	$74

Income Taxes

We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts on our financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

We apply the provisions of Financial Accounting Standards Board (FASB) Interpretation No. 48, “Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109,” (FIN 48). During the second quarter of 2009, there was no change to our FIN 48 liability. As of June 30, 2009, we had not accrued interest or penalties related to uncertain tax positions. The tax years 2005-2008 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject. During the fourth quarter of 2008, the Internal Revenue Service commenced a limited scope audit of our U.S. income tax return for the 2005 tax year.

Derivative Financial Instruments

We account for our derivative activities under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended by SFAS Nos. 137, 138, 149 and 161 (SFAS No. 133). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet at its fair value. The statement requires that changes in the derivative’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Substantially all of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price risk management activities as accounting hedges under SFAS No. 133, and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings. We also utilize derivatives to manage our exposure to variable interest rates.

Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on our consolidated balance sheet. Please see Note 7, "Derivative Financial Instruments," for a more detailed discussion of our derivative activities.

Subsequent Events

As of July 24, 2009, which is the date these financial statements were issued, we completed our review and analysis of potential subsequent events and none were identified.

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New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for all recurring measures of financial assets and financial liabilities (e.g. derivatives and investment securities) for fiscal years beginning after November 15, 2007. We adopted the provisions of SFAS No. 157 for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB issued Staff Position No. 157-2, "Effective Date of FASB Statement No. 157" (FSP 157-2), which granted a one-year deferral of the effective date of SFAS No. 157 as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and asset retirement obligations). Beginning January 1, 2009, we applied SFAS No. 157 to non-financial assets and liabilities. The adoption of SFAS No. 157 did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (SFAS No. 161). This statement requires enhanced disclosures about our derivative and hedging activities. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements of SFAS No. 161 beginning January 1, 2009. Please see Note 7, "Derivative Financial Instruments – Additional Disclosures about Derivative Instruments and Hedging Activities." The adoption of this statement did not have an impact on our financial position or results of operations.

In April 2009, the FASB issued three FASB Staff Positions (FSPs) to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157. FSP FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments," enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments," provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. These three FSPs are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the provisions of these FSPs for the period ending March 31, 2009. The adoption of these FSPs did not have a material impact on our financial position or results of operations.

In May 2009, the FASB issued SFAS No. 165, "Subsequent Events" (SFAS No. 165). SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist. This statement, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. We adopted the statement for the period ending June 30, 2009. The adoption of this statement did not have an impact on our financial position or results of operations.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted shares and restricted stock units (using the treasury stock method). Under the treasury stock method, the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. Please see Note 11, “Stock-Based Compensation.”

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for the indicated periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions, except per share data)			
Income (numerator):				
Net loss – basic and diluted	$ (39)	$ (244)	$ (733)	$ (308)
Weighted average shares (denominator):				
Weighted average shares — basic	130	129	129	129
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period (1)				
Weighted average shares — diluted	130	129	129	129
Loss per share:				
Basic	$ (0.30)	$ (1.89)	$ (5.66)	$ (2.39)
Diluted	$ (0.30)	$ (1.89)	$ (5.66)	$ (2.39)

(1) The effect of stock options and unvested restricted stock and restricted stock units outstanding has not been included in the calculation of shares outstanding for diluted EPS for the three and six months ended June 30, 2009 and 2008 as their effect would have been anti-dilutive. Had we recognized net income for these periods, incremental shares attributable to the assumed exercise of outstanding options and the assumed vesting of unvested restricted stock and restricted stock units would have increased diluted weighted average shares outstanding by 2 million shares for both the three and six months ended June 30, 2009 and 3 million shares for both the three and six months ended June 30, 2008.

3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	June 30, 2009	December 31, 2008
	(In millions)	
Oil and Gas Properties:		
Subject to amortization	$8,371	$8,961
Not subject to amortization:		
Exploration in progress	238	207
Development in progress	60	71

Capitalized interest	131	129
Fee mineral interests	23	23
Other capital costs:		
Incurred in 2009	31	
Incurred in 2008	234	328
Incurred in 2007	214	242
Incurred in 2006 and prior	287	303
Total not subject to amortization	1,218	1,303
Gross oil and gas properties	9,589	10,264
Accumulated depreciation, depletion and amortization	(4,841)	(4,550)
Net oil and gas properties	4,748	5,714
Other property and equipment	87	85
Accumulated depreciation and amortization	(46)	(41)
Net other property and equipment	41	44
Property and equipment, net	$4,789	$5,758

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

4. Debt:

As of the indicated dates, our debt consisted of the following:

	June 30, 2009	December 31, 2008
	(In millions)	
Senior unsecured debt:		
Revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans	594	514
Total revolving credit facility	594	514
Money market lines of credit (1)	45	47
Total credit arrangements	639	561
7 5/8% Senior Notes due 2011	175	175
Fair value of interest rate swap (2)	3	2
Total senior unsecured notes	178	177
Total senior unsecured debt	817	738
6 5/8% Senior Subordinated Notes due 2014	325	325
6 5/8% Senior Subordinated Notes due 2016	550	550
7 1/8% Senior Subordinated Notes due 2018	600	600
Total debt	$2,292	$2,213

(1) Because capacity under our credit facility was available to repay borrowings under our money market lines of credit as of the indicated dates, amounts outstanding under these obligations, if any, are classified as long-term.

(2) We have hedged $50 million principal amount of our $175 million 7 5/8% Senior Notes due 2011. The hedge provides for us to pay variable and receive fixed interest payments. Please see Note 7, "Derivative Financial Instruments – Interest Rate Swap."

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 June 30, 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 natural gas prices because the amount that we can borrow under the facility is determined by our lenders annually each May (and may be redetermined 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 loan 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.

Loans under the credit facility bear interest, at our option, equal to (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (87.5 basis points per annum at June 30, 2009).

We pay commitment fees on available but undrawn amounts based on a grid of our debt rating (0.175% per annum at June 30, 2009). We incurred fees under this arrangement of approximately $0.3 million and $0.7 million for the three and six months ended June 30, 2009, respectively, which are recorded in interest expense on our consolidated statement of income. For the three and six months ended June 30, 2008, we incurred commitment fees of approximately $0.5 million and $1 million, respectively.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Our credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0; maintenance of a ratio of total debt to earnings before gain or loss on the disposition of assets, interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns, and goodwill impairments) of at least 3.5 to 1.0. In addition, for as long as our debt rating is below investment grade, we must maintain a ratio of the calculated net present value of our oil and gas properties to total debt of at least 1.75 to 1.00. For purposes of this ratio, total debt includes only 50% of the principal amount of our senior subordinated notes. At June 30, 2009 we were in compliance with all of our debt covenants.

As of June 30, 2009, we had $22 million of undrawn letters of credit outstanding under our credit facility. Letters of credit are subject to an issuance fee of 12.5 basis points and annual fees based on a grid of our debt rating (87.5 basis points at June 30, 2009).

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $120 million of borrowing capacity under money market lines of credit with various institutions, the availability of which is at the discretion of the financial institutions.

Our credit facility and senior and senior subordinated notes contain standard events of default and, if any such events of default were to occur, our lenders could terminate future lending commitments under the credit facility and our lenders could declare the outstanding borrowings due and payable. In addition, our credit facility, senior subordinated notes and substantially all of our hedging arrangements contain provisions that provide for cross defaults and acceleration of those debt and hedging instruments in certain situations.

5. Commitments and Contingencies:

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.

6. Segment Information:

While we only have operations in the oil and gas exploration and production industry, we are organizationally structured along geographic operating segments. Our current operating segments are the United States, Malaysia, China and Other International. The accounting policies of each of our operating segments are the same as those described in Note 1, "Organization and Summary of Significant Accounting Policies."

The following tables provide the geographic operating segment information required by SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," as of and for the three and six months ended June 30, 2009 and 2008. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	United States	Malaysia	China	Other International	Total
			(In millions)		
Three Months Ended June 30, 2009:					
Oil and gas revenues	$222	$51	$14	$ ¾	$287
Operating expenses:					
Lease operating	45	11	1	¾	57
Production and other taxes	12	2	1	¾	15
Depreciation, depletion and amortization	110	23	4	¾	137
General and administrative	32	2	¾	¾	34
Other	5	¾	¾	¾	5
Allocated income taxes	7	5	2	¾	
Net income from oil and gas properties	$11	$8	$6	$ ¾	
Total operating expenses					248
Income from operations					39
Interest expense, net of interest income, capitalized interest and other					(18)
Commodity derivative expense					(81)
Loss before income taxes					$(60)
Total long-lived assets	$4,250	$366	$129	$ 3	$4,748
Additions to long-lived assets	$276	$4	$20	$ ¾	$300

	United States	Malaysia	China	Other International	Total
			(In millions)		
Three Months Ended June 30, 2008:					
Oil and gas revenues	$602	$68	$21	$ ¾	$691
Operating expenses:					
Lease operating	46	11	1	¾	58
Production and other taxes	22	25	5	¾	52
Depreciation, depletion and amortization	148	14	4	¾	166
General and administrative	36	1	¾	¾	37
Allocated income taxes	133	7	3	¾	
Net income from oil and gas properties	$217	$10	$8	$ ¾	
Total operating expenses					313
Income from operations					378
Interest expense, net of interest income,					(15)

capitalized interest and other					
Commodity derivative expense					(652)
Loss before income taxes					$(289)
Total long-lived assets	$6,330	$421	$103	$ 2	$6,856
Additions to long-lived assets	$686	$40	$4	$ ¾	$730

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	United States	Malaysia	China (In millions)	Other International	Total
Six Months Ended June 30, 2009:					
Oil and gas revenues	$436	$94	$19	$ ¾	$549
Operating expenses:					
Lease operating	104	21	3	¾	128
Production and other taxes	19	4	1	¾	24
Depreciation, depletion and amortization	244	46	6	¾	296
General and administrative	64	1	1	¾	66
Ceiling test writedown	1,344	¾	¾	¾	1,344
Other	7	¾	¾	¾	7
Allocated income taxes	(484)	8	2	¾	
Net income (loss) from oil and gas properties	$(862)	$14	$6	$ ¾	
Total operating expenses					1,865
Loss from operations					(1,316)
Interest expense, net of interest income, capitalized interest and other					(33)
Commodity derivative income					197
Loss before income taxes					$(1,152)
Total long-lived assets	$4,250	$366	$129	$ 3	$4,748
Additions to long-lived assets	$615	$28	$26	$ ¾	$669

	United States	Malaysia	China (In millions)	Other International	Total
Six Months Ended June 30, 2008:					
Oil and gas revenues	$ 1,028	$ 143	$ 36	$ ¾	$ 1,207
Operating expenses:					
Lease operating	93	22	2	¾	117
Production and other taxes	44	52	7	¾	103
Depreciation, depletion and amortization	284	33	6	¾	323
General and administrative	67	1	1	¾	69
Allocated income taxes	206	13	6	¾	
Net income from oil and gas properties	$ 334	$ 22	$ 14	$ ¾	
Total operating expenses					612

Income from operations										595	
Interest expense, net of interest income, capitalized interest and other										(18	)
Commodity derivative expense										(973	)
Loss before income taxes									$	(396	)
Total long-lived assets	$	6,330	$	421	$	103	$	2	$	6,856	
Additions to long-lived assets	$	1,126	$	87	$	31	$	¾	$	1,244	

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

7. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize swap, floor, collar and three-way collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put. None of our derivative contracts contain collateral posting requirements; however, one of our derivative contracts contains a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contract.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet. Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model. Please see Note 13, “Fair Value Measurements.” We recognize all unrealized and realized gains and losses related to these contracts on a mark-to-market basis in our consolidated statement of income under the caption “Commodity derivative income (expense).” Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

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.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At June 30, 2009, we had outstanding contracts with respect to our future production that are not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu					Estimated Fair Value
			Collars				
		Swaps	Floors		Ceilings		
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Asset (Liability)
							(In millions)
July 2009 – September 2009							
Price swap contracts	22,150	$ 7.81	¾	¾	¾	¾	$ 86
Collar contracts	13,620	—	$ 8.00	$ 8.00	$ 8.97 – $14.37	$ 11.83	56
October 2009–December 2009							
Price swap contracts	26,120	7.34	¾	¾	¾	¾	63
Collar contracts	8,435	—	8.00 – 8.50	8.23	8.97 – 14.37	11.20	30
January 2010 – March 2010							
Price swap contracts	31,800	6.79	¾	¾	¾	¾	30
Collar contracts	5,700	—	8.50	8.50	10.00 – 11.00	10.44	15
April 2010 – June 2010							
Price swap contracts	34,850	6.41	¾	¾	¾	¾	22
July 2010 – September 2010							
Price swap contracts	35,200	6.41	¾	¾	¾	¾	13
October 2010 – December 2010							
Price swap contracts	25,270	6.47	¾	¾	¾	¾	(1)
							$ 314

Oil

					NYMEX Contract Price Per Bbl Collars					
		Swaps	Additional Put		Floors		Ceilings		Floors	
Period and Type of Contract	Volume in MBbls	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	Range	We Av
July 2009 - September 2009										
Price swap contracts	828	$128.93	¾	¾	¾	¾	¾	¾	¾	¾
Floor contracts	828	—	—	—	—	—	—	—	$104.50-$109.75	$1
October 2009–December 2009										
Price swap contracts	828	128.93	¾	¾	¾	¾	¾	¾	¾	¾
Floor contracts	828	—	—	—	—	—	—	—	104.50-109.75	1
January 2010 – March 2010										
Price swap contracts	90	93.40	¾	¾	¾	¾	¾	¾	¾	¾
Collar contracts	810	—	¾	¾	$125.50–$130.50	$127.97	$170.00	$170.00	¾	¾
3-Way collar contracts	180	—	$50.00	$50.00	60.00	60.00	112.00-112.10	112.05	¾	¾
April 2010 – June 2010										
Price swap contracts	90	93.40	¾	¾	¾	¾	¾	¾	¾	¾
Collar contracts	819	—	—	¾	125.50–130.50	127.97	170.00	170.00	¾	¾
3-Way collar contracts	182	—	50.00	50.00	60.00	60.00	112.00-112.10	112.05	¾	¾
July 2010 – September 2010										
Price swap contracts	90	93.40	¾	¾	¾	¾	¾	¾	¾	¾
Collar contracts	828	—	—	¾	125.50–130.50	127.97	170.00	170.00	¾	¾

3-Way collar contracts	184	—	50.00	50.00	60.00	60.00	112.00-112.10	112.05	¾	¾
October 2010 – December 2010										
Price swap contracts	90	93.40	¾	¾	¾	¾	¾	¾	¾	¾
Collar contracts	828	—	—	¾	125.50–130.50	127.97	170.00	170.00	¾	¾
3-Way collar contracts	184	—	50.00	50.00	60.00	60.00	112.00-112.10	112.05	¾	¾

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Basis Contracts

At June 30, 2009, we had natural gas basis contracts that are not designated for hedge accounting to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points in the Rocky Mountains, as set forth in the table below.

	Volume in MMMBtus	Weighted Average Differential
July 2009 – September 2009	1,380	$(1.05)
October 2009 – December 2009	1,380	(1.05)
January 2010 – December 2010	5,520	(0.99)
January 2011 – December 2011	5,280	(0.95)
January 2012 – December 2012	4,920	(0.91)

The estimated fair value of each of these basis contracts was approximately $0 at June 30, 2009.

Interest Rate Swap

We entered into an interest rate swap agreement to take advantage of low interest rates and to obtain what we viewed as a more desirable proportion of variable and fixed rate debt. The agreement is designated as a fair value hedge of $50 million principal amount of our $175 million 7 5/8% Senior Notes due 2011. The interest rate swap provides for us to pay variable and receive fixed interest payments. Pursuant to SFAS No. 133, changes in the fair value of derivatives designated as fair value hedges are recognized as offsets to the changes in the fair value of the exposure being hedged. As a result, the fair value of our interest rate swap is reflected as a derivative asset or liability on our consolidated balance sheet and changes in its fair value are recorded as an adjustment to the carrying value of the associated long-term debt. Receipts and payments related to our interest rate swap are reflected in interest expense. The related cash flow impact is reflected as cash flows from operating activities in our consolidated statement of cash flows.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Additional Disclosures about Derivative Instruments and Hedging Activities

At June 30, 2009, we had derivative financial instruments under SFAS No. 133 recorded in our balance sheet as set forth below.

Type of Contract	Balance Sheet Location	Estimated Fair Value (In millions)
Derivative Assets		
Derivatives not designated as hedging instruments:		
Natural gas contracts	Derivative assets – current	$ 302
Oil contracts	Derivative assets – current	245
Basis contracts	Derivative assets – current	
Natural gas contracts	Derivative assets – noncurrent	12
Oil contracts	Derivative assets – noncurrent	88
Basis contracts	Derivative assets – noncurrent	
Total derivatives not designated as hedging instruments		647
Derivative designated as a fair value hedge:		
Interest rate swap	Derivative assets – current	2
Interest rate swap	Derivative assets – noncurrent	1
Total derivative designated as hedging instruments		3
Total Derivative Assets		$ 650

The amount of gain (loss) recognized in income related to our derivative financial instruments under SFAS No. 133 for the indicated periods was as follows:

Type of Contract	Location of Gain/(Loss) Recognized in Income	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Commodity derivative income (expense)	$ 20	$ 294
Oil contracts	Commodity derivative income (expense)	(96)	(79)
Basis contracts	Commodity derivative income (expense)	(5)	(18)

Derivative designated as a fair value hedge:			
Interest rate swap	Interest expense	1	1
Total		$ (80)	$ 198

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate derivative instruments with that counterparty. At June 30, 2009, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to 86% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

A significant number of the counterparties to our derivative instruments also are lenders under our credit facility. Our credit facility, senior subordinated notes and substantially all of our derivative instruments contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

8. Accounts Receivable:

As of the indicated dates, our accounts receivable consisted of the following:

	June 30, 2009	December 31, 2008
	(In millions)	
Revenue	$133	$157
Joint interest	143	197
Other	20	26
Reserve for doubtful accounts	(6)	(5)
Total accounts receivable	$290	$375

9. Accrued Liabilities:

As of the indicated dates, our accrued liabilities consisted of the following:

	June 30, 2009	December 31, 2008
	(In millions)	
Revenue payable	$60	$75
Accrued capital costs	196	319
Accrued lease operating expenses	49	50
Employee incentive expense	47	73
Accrued interest on long-term debt	25	25
Taxes payable	66	69
Other	52	61
Total accrued liabilities	$495	$672

10. Comprehensive Income (Loss):

For the periods indicated, our comprehensive loss consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Net loss	$ (39)	$ (244)	$ (733)	$ (308)
Unrealized gain (loss) on investments, net of tax of ($1) for the three months ended June 30, 2009 and net of tax of $2 for the three and six months ended June 30, 2008	2	(4)		(4)
Total comprehensive loss	$ (37)	$ (248)	$ (733)	$ (312)

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11. Stock-Based Compensation:

We apply SFAS No. 123(R), “Share-Based Payment,” to account for stock-based compensation. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and a lattice-based model for our performance and market-based restricted shares and restricted share units.

Historically, we have used unissued shares of stock when stock options are exercised. Beginning in 2009, we began to utilize treasury shares when stock options are exercised or when restricted stock is issued. At June 30, 2009, we had approximately 2.6 million additional shares available for issuance pursuant to our existing employee and director plans. Of these shares, 1.8 million could be granted as restricted stock or restricted stock units. On May 7, 2009, at Newfield’s 2009 annual meeting of stockholders, Newfield’s stockholders approved the Newfield Exploration Company 2009 Omnibus Stock Plan (the “2009 Omnibus Stock Plan”) and Newfield’s 2000 omnibus stock plan, 2004 omnibus stock plan and 2007 omnibus stock plan (which were used for equity grants to employees) were terminated such that no new grants will be made under those previous plans. Outstanding awards under those previous plans were not impacted by the termination of those previous plans. Shares available for grant under our 2009 Omnibus Stock Plan are reduced by 1.5 times the number of shares of restricted stock or restricted stock units awarded under the plan, and are reduced by 1 times the number of shares subject to stock options awarded under the plan. Of the 1.8 million shares that can be granted as restricted stock or restricted stock units, 1.6 million can be issued under our 2009 Omnibus Stock Plan.

For the three month periods ended June 30, 2009 and 2008, we recorded stock-based compensation of $11 million and $10 million, respectively, for all plans. Of these amounts, $4 million and $3 million, respectively, were capitalized in oil and gas properties.

For the six month periods ended June 30, 2009 and 2008, we recorded stock-based compensation expense of $23 million and $17 million, respectively, for all plans. Of these amounts, $8 million and $5 million, respectively, were capitalized in oil and gas properties.

The excess tax benefit realized from stock options exercised is recognized as a credit to additional paid in capital and is calculated as the amount by which the tax deduction we receive exceeds the deferred tax asset associated with recorded stock compensation expense. We did not realize an excess tax benefit from stock compensation for the six months ended June 30, 2009 because we do not anticipate having sufficient taxable income to fully realize the deduction. Any excess tax benefits associated with the exercise of stock options in 2009 will be realized when the deduction can be utilized to reduce current income taxes on future tax returns. The amount credited to additional paid in capital for the six months ended June 30, 2008 was $4 million.

As of June 30, 2009, we had approximately $73 million of total unrecognized compensation expense related to unvested stock-based compensation awards. This compensation expense is expected to be recognized on a straight-line basis over the applicable remaining vesting period. The full amount is expected to be recognized within approximately five years.

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NEWFIELD EXPLORATION COMPANY
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Stock Options. We have granted stock options under several plans. The exercise price of options cannot be less than the fair market value per share of our common stock on the date of grant.

The following table provides information about stock option activity for the six months ended June 30, 2009:

	Number of Shares Underlying Options (In millions)	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life (In years)	Aggregate Intrinsic Value(1) (In millions)
Outstanding at December 31, 2008	3.5	$28.74		5.5	$3.0
Granted			$		
Exercised	(0.1)	16.23			
Forfeited	(0.1)	38.80			
Outstanding at June 30, 2009	3.3	$28.95		5.0	$22.5
Exercisable at June 30, 2009	2.6	$25.77		4.4	$22.1

(1) The intrinsic value of a stock option is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the option.

On June 30, 2009, the last reported sales price of our common stock on the New York Stock Exchange was $32.67 per share.

The following table summarizes information about stock options outstanding and exercisable at June 30, 2009:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options (In millions)	Weighted Average Remaining Contractual Life (In years)	Weighted Average Exercise Price per Share	Number of Shares Underlying Options (In millions)	Weighted Average Exercise Price per Share
$12.51 to $15.00	0.1	0.6	$ 14.89	0.1	$ 14.89
15.01 to 17.50	0.6	3.1	16.63	0.6	16.63
17.51 to 22.50	0.4	2.8	18.89	0.4	18.89
22.51 to 27.50	0.5	4.7	24.78	0.5	24.77
27.51 to 35.00	0.9	5.5	31.15	0.7	31.21
35.01 to 41.72	0.2	5.8	37.50	0.1	37.46

41.73 to 48.45	0.6	8.6		48.45	0.2	48.45
	3.3	5.0	$	28.95	2.6	$ 25.77

Restricted Shares. At June 30, 2009, our employees held 2.4 million restricted shares or restricted share units that primarily vest over a service period of four or five years. The vesting of these shares and units is dependant upon the employee's continued service with our company. In addition, at June 30, 2009, our employees held 0.8 million restricted shares subject to performance-based vesting criteria (substantially all of which are considered market-based restricted shares under SFAS No. 123(R)).

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table provides information about restricted share and restricted share unit activity for the six months ended June 30, 2009:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted Average Grant Date Fair Value per Share
	(In thousands, except per share data)			
Non-vested shares outstanding at December 31, 2008	1,679	1,208	2,887	$34.58
Granted	1,010		1,010	22.05
Forfeited	(36)	(316)	(352)	26.21
Vested	(223)	(110)	(333)	35.29
Non-vested shares outstanding at June 30, 2009	2,430	782	3,212	$31.48

The total fair value of restricted shares that vested during the six months ended June 30, 2009 was $12 million.

Employee Stock Purchase Plan. Pursuant to our employee stock purchase plan, for each six month period beginning on January 1 or July 1 during the term of the plan, each eligible employee has the opportunity to purchase our common stock for a purchase price equal to 85% of the lesser of the fair market value of our common stock on the first day of the period or the last day of the period. No employee may purchase common stock under the plan valued at more than $25,000 in any calendar year. Employees of our foreign subsidiaries are not eligible to participate in the plan.

During the second quarter of 2009, we sold 88,294 shares of our common stock under the plan. The weighted average fair value of the option to purchase stock under the plan during the first half of 2009 was $7.89 per share. The fair value of the options granted was determined using the Black-Scholes option valuation method assuming no dividends, a risk-free weighted average interest rate of 0.27%, an expected life of six months and weighted average volatility of 90%. At June 30, 2009, 409,564 shares of our common stock remained available for issuance under the plan.

12. Income Taxes:

The income tax benefit for the indicated periods was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In millions)			
Amount computed using the statutory rate	$ (21)	$ (100)	$ (404)	$ (138)
Increase (decrease) in taxes resulting from:				

State and local income taxes, net of federal effect	1	55	(17)	49
Net effect of different tax rates in non-U.S. jurisdictions	1		1	1
Valuation allowances	(3)			
Other (1)	1		1	
Total income tax benefit	$ (21)	$ (45)	$ (419)	$ (88)

(1) Our interim period tax provision for 2008 was calculated based on statutory tax rates applied to pre-tax earnings as adjusted for permanent differences. An annualized projected effective tax rate was not applied because of our inability to develop a reliable estimate of our pre-tax income, which was subject to significant variability due to changes in the fair value of our then open commodity derivative instruments. This resulted in significant fluctuations in the reported tax provision in these interim periods.

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As of June 30, 2009, we had net operating loss (NOL) carryforwards for international income tax purposes of approximately $17 million that may be used in future years to offset taxable income, however we currently estimate that we will not be able to utilize these NOLs nor certain deferred tax asset timing differences in Malaysia because we do not anticipate that we will have sufficient estimated future taxable income in the appropriate jurisdictions. Therefore, valuation allowances have been established for these items. Utilization of NOL carryforwards is dependent upon generating sufficient taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

13. Fair Value Measurements:

We adopted SFAS No. 157, "Fair Value Measurements," effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and liabilities that are being measured and reported on a fair value basis. Beginning January 1, 2009, we also applied SFAS No. 157 to non-financial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires that fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps, investments and interest rate swaps.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider 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, as well as other relevant economic measures. Our valuation methodology for investments is a discounted cash flow model that considers various inputs including: (a) the coupon rate specified under the debt instruments, (b) the current credit ratings of the underlying issuers, (c) collateral characteristics and (d) risk adjusted discount rates. Level 3 instruments primarily include derivative instruments, such as basis swaps, commodity price collars and floors and some financial investments. Although we utilize third party broker quotes to assess the reasonableness of our prices and valuation techniques, we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Fair Value of Derivative Instruments

The following table summarizes the valuation of our investments and financial instruments by SFAS No. 157 pricing levels as of June 30, 2009:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets (Liabilities):		(In millions)		
Investments available-for-sale:				
Equity securities	$ 8	$	$	$ 8
Auction rate securities			45	45
Oil and gas derivative swap contracts		314		314
Oil and gas derivative option contracts			333	333
Interest rate swap		3		3
Total	$ 8	$ 317	$ 378	$ 703

The determination of the fair values above incorporates various factors required under SFAS No. 157. These factors include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests). We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties.

As of June 30, 2009, we continued to hold $45 million of auction rate securities which have maturities beginning in 2033 that are classified as a Level 3 fair value measurement. This amount reflects a decrease in the fair value of these investments of $17 million ($11 million net of tax), recorded under the caption “Accumulated other comprehensive income (loss)” on our consolidated balance sheet. The debt instruments underlying these investments are investment grade (rated BBB- or better) and are guaranteed by the United States government or backed by private loan collateral. We do not believe the decrease in the fair value of these securities is permanent because we currently intend to hold these investments until the auction succeeds, the issuer calls the securities or the securities mature. Our current available borrowing capacity under our credit arrangements provides us the liquidity to continue to hold these securities.

The following tables set forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated periods:

	Investments	Derivatives	Total
		(In millions)	
Balance at January 1, 2009	$ 59	$ 542	$ 601
Total realized or unrealized gains (losses):			
Included in earnings		(33)	(33)

Included in other comprehensive income (loss)						
Purchases, issuances and settlements		(14)		(176)		(190)
Transfers in and out of Level 3						
Balance at June 30, 2009	$	45	$	333	$	378
Change in unrealized gains (losses) relating to						
investments and derivatives still held at June 30, 2009	$		$	(65)	$	(65)

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Fair Value of Debt

The estimated fair value of our notes, based on quoted market prices on June 30, 2009, was as follows (in millions):

7 5/8% Senior Notes due 2011	$176
6 5/8% Senior Subordinated Notes due 2014	301
6 5/8% Senior Subordinated Notes due 2016	501
7 1/8% Senior Subordinated Notes due 2018	548

Amounts outstanding under our credit arrangements at June 30, 2009 are stated at cost, which approximates fair value. Please see Note 4, “Debt”.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

We are an independent oil and gas company engaged in the exploration, development and acquisition of natural gas and crude oil 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 natural 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 Natural Gas Prices. Prices for oil and natural gas fluctuate widely. Oil and natural 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.

An extended decline in oil and natural 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 resulted in a ceiling test writedown and may in the future result in additional ceiling test writedowns or other impairments" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2008 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 being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and gas 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 are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of June 30, 2009, we had derivative assets of $650 million, of which 51% was measured based upon our valuation model 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 Note 7, “Derivative Financial Instruments,” and Note 13, “Fair Value Measurements,” to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Other factors. Please see “Risk Factors” in Item 1A of our annual report on Form 10-K for the year ended December 31, 2008 and Item 1A of this report for a discussion of a number of other factors that affect our business, financial condition and results of operations. This report should be read together with those discussions.

Results of Operations

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 June 30, 2009 are designated for hedge accounting and the settlement of all oil and gas hedging contracts during the second quarter and first six months of 2009 and 2008 had no effect on reported revenues. Please see Note 7, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in 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 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 $287 million for the second quarter of 2009 were 59% lower than the comparable period of 2008. Revenues of $549 million for the first six months of 2009 were 55% lower than the comparable period of 2008. The revenue decrease during both periods is due to significantly lower average realized oil and natural gas prices partially offset by higher oil and gas production.

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	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Percentage Increase (Decrease)	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Percentage Increase (Decrease)
Production (1):						
Domestic:						
Natural gas (Bcf)	45.2	43.7	4 %	90.1	84.1	7 %
Oil and condensate (MBbls)	1,869	1,528	22 %	3,637	2,950	23 %
Total (Bcfe)	56.4	52.9	7 %	111.9	101.8	10 %
International:						
Natural gas (Bcf)	—	—	—	—	—	—
Oil and condensate (MBbls)	1,365	793	72 %	2,566	1,830	40 %
Total (Bcfe)	8.2	4.7	72 %	15.4	11.0	40 %
Total:						
Natural gas (Bcf)	45.2	43.7	4 %	90.1	84.1	7 %
Oil and condensate (MBbls)	3,234	2,321	39 %	6,203	4,780	30 %
Total (Bcfe)	64.6	57.6	12 %	127.3	112.8	13 %
Average Realized Prices (2):						
Domestic:						
Natural gas (per Mcf)	$ 2.85	$ 9.86	(71)%	$ 3.16	$ 8.75	(64)%
Oil and condensate (per Bbl)	49.24	110.87	(56)%	40.98	98.41	(58)%
Natural gas equivalent (per Mcfe)	3.92	11.35	(65)%	3.88	10.08	(62)%
International:						
Natural gas (per Mcf)	$ —	$ —	—	$ —	$ —	—
Oil and condensate (per Bbl)	47.29	112.85	(58)%	44.19	97.29	(55)%
Natural gas equivalent (per Mcfe)	7.86	18.81	(58)%	7.36	16.22	(55)%
Total:						
Natural gas (per Mcf)	$ 2.85	$ 9.86	(71)%	$ 3.16	$ 8.75	(64)%
Oil and condensate (per Bbl)	48.42	111.55	(57)%	42.31	97.98	(57)%
Natural gas equivalent (per Mcfe)	4.42	11.97	(63)%	4.30	10.67	(60)%

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

(2) Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total gas would have been $6.21 and $7.95 per Mcf for the three months ended June 30, 2009 and 2008, respectively, and $5.84 and $7.92 per Mcf for the six months ended June 30, 2009 and 2008, respectively. Our total oil and condensate average realized price would have been $76.09 and $85.42 per Bbl for the three months ended June 30, 2009 and 2008, respectively, and $75.29 and $77.08 per Bbl for the six months ended June 30, 2009 and 2008, respectively. All amounts for the three and six months ended June 30, 2008 exclude the cash payments to reset our 2009 and 2010 crude oil hedges of $488 million and $502 million, respectively.

Domestic Production. Our three and six months ended June 30, 2009 domestic oil and gas production (stated on a natural gas equivalent basis) increased over the comparable periods of 2008 primarily due to increased production in our Mid-Continent and Rocky Mountain divisions as a result of continued successful drilling efforts.

International Production. Our three and six months ended June 30, 2009 international oil production (stated on a natural gas equivalent basis) increased over the comparable periods of 2008 primarily due to the new field development on PM 323 in Malaysia and the timing of liftings of our oil production in Malaysia.

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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.

The following table presents information about our operating expenses for the three months ended June 30, 2009 and 2008.

	Unit-of-Production			Total Amount		
	Three Months Ended June 30,		Percentage Increase (Decrease)	Three Months Ended June 30,		Percentage Increase (Decrease)
	2009	2008		2009	2008	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 0.80	$ 0.87	(8)%	$ 45	$ 46	(2)%
Production and other taxes	0.21	0.42	(50)%	12	22	(47)%
Depreciation, depletion and amortization	1.94	2.79	(30)%	110	148	(26)%
General and administrative	0.57	0.69	(17)%	32	36	(12)%
Other	0.09	—	100 %	5	—	100 %
Total operating expenses	3.61	4.77	(24)%	204	252	(19)%
International:						
Lease operating	$ 1.44	$ 2.44	(41)%	$ 12	$ 12	(1)%
Production and other taxes	0.34	6.33	(95)%	3	30	(91)%
Depreciation, depletion and amortization	3.33	3.78	(12)%	27	18	52 %
General and administrative	0.22	0.28	(21)%	2	1	37 %
Total operating expenses	5.33	12.83	(58)%	44	61	(28)%
Total:						
Lease operating	$ 0.88	$ 1.00	(12)%	$ 57	$ 58	(1)%
Production and other taxes	0.23	0.91	(75)%	15	52	(72)%
Depreciation, depletion and amortization	2.12	2.87	(26)%	137	166	(17)%
General and administrative	0.52	0.65	(20)%	34	37	(10)%
Other	0.08	—	100 %	5	—	100 %
Total operating expenses	3.83	5.43	(29)%	248	313	(21)%

Domestic Operations. Our domestic operating expenses for the three months ended June 30, 2009, stated on a Mcfe basis, decreased 24% over the same period of 2008. The components of the period to period change are as follows:

- Lease operating expense (LOE) per Mcfe decreased 8% primarily due to lower operating costs for all of our operations.

- Production and other taxes per Mcfe decreased 50% primarily due to significantly lower realized commodity prices during the second quarter of 2009 compared to the same period of 2008.

- Our depreciation, depletion and amortization (DD&A) rate per Mcfe decreased 30% 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 17% primarily due to a decrease in incentive compensation expense, which is calculated based on adjusted net income (as defined in our incentive compensation plan). Adjusted net income for purposes of our incentive compensation plan excludes (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 the second quarter of 2009, we capitalized $15 million of direct internal costs as compared to $13 million in the second quarter of 2008.

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International Operations. Our international operating expenses for the three months ended June 30, 2009, stated on a Mcfe basis, decreased 58% over the same period of 2008. The components of the period to period change are as follows:

- LOE per Mcfe decreased 41% while total LOE remained flat period over period. The decrease in LOE per Mcfe is primarily due to increased production volumes associated with the new field development on PM 323 in Malaysia and lower operating costs.

- Production and other taxes decreased significantly due to substantially lower oil prices during the second quarter of 2009.

- The DD&A rate on an Mcfe basis decreased slightly while total DD&A expense increased 52% primarily due to the additional production volumes associated with the new field development on PM 323 in Malaysia.

- G&A expense decreased $0.06 per Mcfe primarily due to the 72% increase in production volumes period over period.

The following table presents information about our operating expenses for the six months ended June 30, 2009 and 2008.

	Unit-of-Production			Total Amount		
	Six Months Ended June 30,		Percentage Increase (Decrease)	Six Months Ended June 30,		Percentage Increase (Decrease)
	2009	2008		2009	2008	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 0.93	$ 0.91	2 %	$ 104	$ 93	12 %
Production and other taxes	0.17	0.43	(60)%	18	44	(58)%
Depreciation, depletion and amortization	2.18	2.79	(22)%	244	284	(14)%
General and administrative	0.57	0.66	(14)%	64	67	(4)%
Ceiling test writedown	12.02	—	100 %	1,344	—	100 %
Other	0.06	—	100 %	7	—	100 %
Total operating expenses	15.93	4.79	233 %	1,781	488	266 %
International:						
Lease operating	$ 1.57	$ 2.20	(29)%	$ 24	$ 24	—
Production and other taxes	0.34	5.41	(94)%	6	59	(91)%
Depreciation, depletion and amortization	3.39	3.58	(5)%	52	39	33 %
General and administrative	0.13	0.19	(32)%	2	2	(4)%
Total operating expenses	5.43	11.38	(52)%	84	124	(33)%
Total:						
Lease operating	$ 1.00	$ 1.03	(3)%	$ 128	$ 117	10 %
Production and other taxes	0.19	0.92	(79)%	24	103	(77)%
Depreciation, depletion and amortization	2.32	2.86	(19)%	296	323	(8)%
General and administrative	0.52	0.61	(15)%	66	69	(4)%
Ceiling test writedown	10.56	—	100 %	1,344	—	100 %

Other	0.05	—	100 %	7	—	100 %
Total operating expenses	14.64	5.42	170 %	1,865	612	205 %

Domestic Operations. Our domestic operating expenses for the six months ended June 30, 2009, stated on a Mcfe basis, increased 233% over the same period of 2008 primarily due to a full cost ceiling test writedown recorded at March 31, 2009. The components of the period to period change are as follows:

- LOE per Mcfe increased 2% primarily due to increased well workover activity associated with our onshore Texas and deepwater Gulf of Mexico operations compared to the same period of 2008.

- Production and other taxes per Mcfe decreased 60% primarily due to significantly lower realized commodity prices during the first six months of 2009 compared to the same period of 2008.

- Our DD&A rate per Mcfe decreased 22% primarily as a result of the ceiling test writedowns recorded at December 31, 2008 and March 31, 2009.

- G&A expense per Mcfe decreased 14% primarily due to a decrease in incentive compensation expense, which is calculated based on adjusted net income (as defined in our incentive compensation plan). Adjusted net income for purposes of our incentive compensation plan excludes (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 the first six months of 2009, we capitalized $28 million of direct internal costs as compared to $24 million in the first six months of 2008.

- We recorded a ceiling test writedown of $1.3 billion ($12.02 per Mcfe) due to significantly lower natural gas prices at March 31, 2009.

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International Operations. Our international operating expenses for the six months ended June 30, 2009, stated on a Mcfe basis, decreased 52% over the same period of 2008. The period to period change was primarily related to the following items:

- LOE per Mcfe decreased 29% while total LOE remained flat period over period. The decrease in LOE per Mcfe is primarily due to increased production volumes associated with the new field development on PM 323 in Malaysia and lower operating costs.

- Production and other taxes decreased significantly due to substantially lower oil prices during the first six months of 2009.

- The DD&A rate on an Mcfe basis decreased slightly while total DD&A expense increased 33% during the first six months of 2009 primarily due to the additional production volumes associated with the new field development on PM 323 in Malaysia.

- G&A expense per Mcfe decreased $0.06 primarily due to the 40% increase in total international production volumes period over period.

Commodity Derivative Income (Expense)

Commodity derivative expense during the second quarter of 2009 decreased $571 million over the same period of 2008 and commodity derivative income for the first six months of 2009 increased $1.2 billion over the same period of 2008. The significant fluctuation from period to period is due to the extreme volatility of oil and natural gas prices and changes in our outstanding hedging contracts during these periods.

Interest Expense

The following table presents information about interest expense for the indicated periods.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Gross interest expense:				
Credit arrangements	$ 2	$ 2	$ 5	$ 3
Senior notes	3	3	6	7
Senior subordinated notes	26	21	51	35
Other	1	2	2	2
Total gross interest expense	32	28	64	47
Capitalized interest	(12)	(13)	(26)	(27)
Net interest expense	$ 20	$ 15	$ 38	$ 20

The increase in gross interest expense for both the three and six month periods ended June 30, 2009 over the comparable prior periods resulted primarily from the May 2008 issuance of $600 million principal amount of our 7 1/8% Senior Subordinated Notes due 2018.

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Taxes. The effective tax rates for the second quarter of 2009 and 2008 were 35.4% and 15.6%, respectively. The effective tax rates for the first six months of 2009 and 2008 were 36.4% and 22.3%, respectively. The change in our effective tax rates for the three and six month periods ended June 30, 2008 as compared to the comparable periods of 2009 were due to significant changes in the proportion of our 2008 book income in separate state taxing jurisdictions compared to total consolidated domestic book income. Certain corporate items, such as hedging losses, are not includable in determining taxable income for the state of Oklahoma; however these items are included in the determination of consolidated U.S. federal income taxes. Our effective tax rate for all periods was different than the federal statutory tax rate due to deductions that do not generate tax benefits, state income taxes and the differences between international and U.S. federal statutory rates. Estimates of future taxable income can be significantly affected by changes in oil and natural 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 natural 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. In light of the current economic outlook and commodity price environment, we intend to limit our 2009 capital expenditures to a level that we expect can be funded with cash flow from operations, thereby preserving liquidity under our credit arrangements. Our 2009 capital budget focuses on those projects that we believe will generate and lay the foundation for production growth. We have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

Although our 2009 capital budget is set at a level that we believe corresponds with our anticipated 2009 cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match, and we anticipate borrowing and repaying funds under our credit arrangements throughout the year. For example, our capital expenditures were front-end loaded and we outspent cash flows in the first half of 2009. We may have to further reduce capital expenditures and our ability to execute our business plans could be diminished 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 natural 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.

We continue to hold auction rate securities with a fair value of $45 million. We will attempt to sell these securities every 7-28 days until the auction succeeds, 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 or 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. Please see Note 13, “Fair Value Measurements” for more information regarding the auction rate securities.

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 June 30, 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 natural gas prices because the amount that we may borrow under the facility is determined by our lenders annually each May (and may be redetermined 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 loan 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. 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 institution. For a more detailed description of the terms of our credit arrangements, please see Note 4, "Debt," to our consolidated financial statements appearing earlier in this report.

At July 22, 2009, we had outstanding borrowings of $594 million under our $1.25 billion credit facility and $17 million outstanding under our money market lines of credit and we had approximately $736 million of available borrowing capacity under our credit arrangements.

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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 because our capital spending generally has exceeded our cash flows from operations and we generally use excess cash to pay down borrowings outstanding under our credit arrangements. For the full year 2009 we expect that our capital spending plans will match our total cash flows from operations.

At June 30, 2009, we had positive working capital of $262 million compared to $121 million at December 31, 2008. The increase in our working capital balance at June 30, 2009 is primarily related to the decrease in our accrued liabilities of $177 million due to lower capital spending in 2009.

Cash Flows from Operations. Cash flows from operations 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 natural gas production under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months. See “Oil and Gas Hedging” below.

We typically receive the cash associated with accrued 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 and other impairments or other non-cash charges or credits.

Our net cash flow from operations was $712 million for the six months ended June 30, 2009, an increase of 314% compared to net cash flow from operations of $172 million for the same period in 2008. This increase is primarily due to cash receipts on derivative settlements during the first six months of 2009 compared to cash payments associated with derivative settlements during the comparable period of 2008. In addition, 2008 net cash flow from operations includes the $558 million payment to reset our 2009 and 2010 crude oil hedging contracts.

Cash Flows from Investing Activities. Net cash used in investing activities for the six months ended June 30, 2009 was $776 million compared to $1.3 billion for the same period in 2008.

During the six months ended June 30, 2009, we:

- spent $790 million (including $9 million for acquisitions of oil and gas properties); and
- redeemed investments of $14 million.

During the six months ended June 30, 2008, we:

- spent $1.3 billion (including $231 million for acquisitions of oil and gas properties); and
- purchased investments of $22 million and redeemed investments of $70 million.

Capital Expenditures. Our capital expenditures of $664 million for the first six months of 2009 decreased 47% from our capital expenditures of $1.2 billion during the same period of 2008. These amounts exclude recorded asset retirement costs of $5 million and $2 million in 2009 and 2008, respectively. Of the $664 million spent during the first six months of 2009, we invested $495 million in domestic exploitation and development, $89 million in domestic exploration (exclusive of exploitation and leasehold activity), $26 million in domestic leasehold activity and

$54 million internationally. Of the $1.2 billion spent during the first six months of 2008, we invested $623 million in domestic exploitation and development, $188 million in domestic exploration (exclusive of exploitation and leasehold activity), $312 million in domestic leasehold activity (includes the acquisition of properties in South Texas) and $119 million internationally.

Our 2009 capital expenditures budget is $1.45 billion, including $130 million of estimated capitalized interest and overhead. Today, approximately 46% of the budget before capitalized interest and overhead is allocated to the Mid-Continent, 16% to the Rocky Mountains, 16% to the Gulf of Mexico, 12% to onshore Texas, and 10% to international projects. See Item 1, "Business — Our Properties and Plans for 2009," in our annual report on Form 10-K for the year ended December 31, 2008. The 2009 budget is based on our commitment to operate within expected cash flow from operations. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and natural gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. 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 flow provided by financing activities for the first six months of 2009 was $78 million compared to $878 million for the same period in 2008.

During the first six months of 2009, we borrowed $732 million and repaid $654 million under our credit arrangements.

During the first six months of 2008, we:

- borrowed $1.2 billion and repaid $1.0 billion under our credit arrangements;
- issued $600 million aggregate principal amount of our 7 1/8% Senior Subordinated Notes due 2018 and paid $8 million in associated debt issue costs; and
- received proceeds of $18 million from the issuance of shares of our common stock upon the exercise of stock options.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of June 30, 2009.

	Total	Less than 1 Year	2-3 Years (In millions)	4-5 Years	More than 5 Years
Debt:					
Revolving credit facility	$639	$—	$639	$—	$—
7 5/8% Senior Notes due 2011	175	—	175	—	—
6 5/8% Senior Subordinated Notes due 2014	325	—	—	—	325
6 5/8% Senior Subordinated Notes due 2016	550	—	—	—	550
7 1/8% Senior Subordinated Notes due 2018	600	—	—	—	600
Total debt	2,289	—	814	—	1,475
Other obligations:					
Interest payments(1)	807	122	230	201	254
Net derivative liabilities (assets)	(650)	(549)	(101)	—	—
Asset retirement obligations	79	5	7	4	63
Operating leases	154	79	27	18	30
Deferred acquisition payments	2	2	—	—	—
Firm transportation	233	26	56	55	96
Oil and gas activities(2)	514	—	—	—	—
Total other obligations	1,139	(315)	219	278	443
Total contractual obligations	$3,428	$(315)	$1,033	$278	$1,918

(1) Interest associated with our revolving credit facility was calculated using a weighted average interest rate of approximately 1.2% at June 30, 2009 and is included through the maturity of the facility.

(2) As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work-related commitments for, among other things, drilling

wells, obtaining and processing seismic data, natural gas transportation, and fulfilling other cash commitments. At June 30, 2009, these work-related commitments totaled $514 million and were comprised of $380 million domestically and $134 million internationally. A significant portion of the domestic amount is related to a 10-year firm transportation agreement for our Mid-Continent production. This obligation is subject to the completion of construction and required regulatory approvals. Annual amounts are not included by maturity because their timing cannot be accurately predicted.

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Oil and Gas Hedging

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and natural gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and natural gas prices. 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 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. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions.

While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate hedging arrangements with that counterparty. At June 30, 2009, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to 86% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

A significant number of the counterparties to our hedging arrangements also are lenders under our credit facility. Our credit facility, senior subordinated notes and substantially all of our hedging arrangements contain provisions that provide for cross defaults and acceleration of those debt and hedging instruments in certain situations. None of our derivative contracts contain collateral posting requirements; however, one of our derivative contracts contains a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contract.

Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically, a majority of our hedged natural gas and crude oil production has been sold at market prices that have had a high positive correlation to the settlement price for such hedges.

The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages \$0.50-\$0.75 per MMBtu less than the Henry Hub Index. Realized gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 70-80% of the Henry Hub Index. Beginning in the third quarter of 2009, our realized prices for our Mid-Continent properties should improve to 75-85% of the Henry Hub Index as we begin to utilize our agreements that provide guaranteed pipeline capacity at a fixed price to move this natural gas production to the Perryville markets. In light of potential basis risk with respect to our Rocky Mountain proved producing fields acquired from Stone Energy, we have hedged the basis differential for about 40% of our estimated production for 2009 through 2012 to lock in the differential at a weighted average of \$0.98 per MMBtu less than the Henry Hub Index. The price we receive for our Gulf Coast oil production typically averages about 90-95% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is currently averaging about \$12-\$14 per barrel below the WTI price. Oil production from our Mid-Continent properties typically averages 85-90% of the WTI price. Oil sales from our operations in Malaysia typically sell at a slight discount to Tapis, or about 85-90% of WTI. Oil sales from our operations in China typically sell at \$6-\$8 per barrel less than the WTI price.

Between July 1, 2009 and July 23, 2009, we entered into additional natural gas derivative contracts as set forth below.

Period and Type of Contract	Volume in MMMBtus	Weighted Average NYMEX Contract Price per MMBtu
January 2011 - March 2011		
Price swap contracts	14,400	$6.51
April 2011 - June 2011		
Price swap contracts	14,560	6.51
July 2011 - September 2011		
Price swap contracts	14,720	6.51
October 2011		
Price swap contracts	4,960	6.51

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New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements” (SFAS No. 157). SFAS No. 157 defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for all recurring measures of financial assets and financial liabilities (e.g. derivatives and investment securities) for fiscal years beginning after November 15, 2007. We adopted the provisions of SFAS No. 157 for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB issued Staff Position No. 157-2, “Effective Date of FASB Statement No. 157” (FSP 157-2), which granted a one-year deferral of the effective date of SFAS No. 157 as it applies to non-financial assets and liabilities that are recognized or disclosed at fair value on a nonrecurring basis (e.g. those measured at fair value in a business combination and asset retirement obligations). Beginning January 1, 2009, we applied SFAS No. 157 to non-financial assets and liabilities. The adoption of SFAS No. 157 did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133” (SFAS No. 161). This statement requires enhanced disclosures about our derivative and hedging activities. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements of SFAS No. 161 beginning January 1, 2009. Please see Note 7, “Derivative Financial Instruments – Additional Disclosures about Derivative Instruments and Hedging Activities.” The adoption of this statement did not have an impact on our financial position or results of operations.

In April 2009, the FASB issued three FASB Staff Positions (FSPs) to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP FAS 157-4, “Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,” provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157. FSP FAS 107-1 and APB 28-1, “Interim Disclosures about Fair Value of Financial Instruments,” enhances consistency in financial reporting by increasing the frequency of fair value disclosures. FSP FAS 115-2 and FAS 124-2, “Recognition and Presentation of Other-Than-Temporary Impairments,” provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. These three FSPs are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the provisions of these FSPs for the period ending March 31, 2009. The adoption of these FSPs did not have a material impact on our financial position or results of operations.

In May 2009, the FASB issued SFAS No. 165, “Subsequent Events” (SFAS No. 165). SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist. This statement, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. We adopted the statement for the period ending June 30, 2009. The adoption of this statement did not have an impact on our financial position or results of operations.

General Information

General information about us can be found at www.newfield.com. In conjunction with our web page, we also maintain an electronic publication entitled @NFX. @NFX is periodically published to provide updates on our operating activities and our latest publicly announced estimates of expected production volumes, costs and expenses for the then current quarter. Recent editions of @NFX are available on our web page. To receive @NFX directly by email, please forward your email address to info@newfield.com or visit our web page and sign up. Unless specifically incorporated, the information about us at www.newfield.com or in any edition of @NFX is not part of this report.

Our annual report 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 or furnish them to the Securities and Exchange Commission.

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Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results, such as planned capital expenditures, the availability and source of capital resources to fund capital expenditures 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 natural gas prices;
- general economic, financial, industry or business conditions;
- 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;
- 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;
- severe weather conditions (such as hurricanes); and
- the other factors affecting our business described under the caption "Risk Factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2008 and Item 1A of this report.

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 and in our annual report on Form 10-K for the year ended December 31, 2008. See "Item 1A. Risk Factors," "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.

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.

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.

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 natural gas.

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

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

Exploitation well. An exploration well drilled to find and produce probable reserves. Most of the exploitation wells we drill 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.

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Exploration well. A well drilled to find and produce oil or natural gas reserves that is not a development well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

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.

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

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.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

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. Reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.

Proved reserves. In general, the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(2) of Regulation S-X.

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 proved undeveloped reserves in Rule 4-10(a)(4) of Regulation S-X.

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 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from changes in oil and natural gas prices, interest rates and foreign currency exchange rates as discussed below.

Oil and Natural Gas Prices

We generally hedge a substantial, but varying, portion of our anticipated 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 NYMEX Henry Hub posted prices and those of our physical pricing points. We use hedging to reduce our exposure to fluctuations in oil and natural gas prices. 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. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While hedging limits the downside risk of adverse price movements, it also may limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. For a further discussion of our hedging activities, see the information under the caption "Oil and Gas Hedging" in Item 2 of this report and the discussion and tables in Note 7, "Derivative Financial Instruments," to our consolidated financial statements appearing earlier in this report.

Interest Rates

At June 30, 2009, our debt included:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Bank revolving credit facility	$	$639
7 5/8% Senior Notes due 2011(1)	125	50
6 5/8% Senior Subordinated Notes due 2014	325	
6 5/8% Senior Subordinated Notes due 2016	550	
7 1/8% Senior Subordinated Notes due 2018	600	
Total debt	$1,600	$689

(1) $50 million principal amount of our 7 5/8% Senior Notes due 2011 is subject to an interest rate swap. The swap provides for us to pay variable and receive fixed interest payments, and is designated as a fair value hedge of a portion of our outstanding senior notes.

We consider our interest rate exposure to be minimal because only about 30% of our debt was at variable rates, after taking into account our interest rate swap agreement. The interest rate on our variable rate debt currently is less than 2%. The impact on annual cash flow of a 10% change in the floating rate applicable to our variable rate debt would be approximately $1 million.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flow, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at June 30, 2009.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2009.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the second quarter of 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. Legal Proceedings

There have been no material changes with respect to our legal proceedings previously reported in our annual report on Form 10-K for the year ended December 31, 2008.

Item 1A. Risk Factors

The risk factor below updates our risk factors previously reported in our annual report on Form 10-K for the year ended December 31, 2008 to specifically reference recent legislative proposals:

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 activities and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations. Changes to existing regulations or 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 of wells, 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.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended June 30, 2009.

	Total Number of	Maximum Number (or Approximate)

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Shares Purchased as Part of Publicly Announced Plans or Programs	Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
April 1 – April 30, 2009	908	$ 22.47	—	—
May 1 – May 31, 2009	25,165	37.47	—	—
June 1 – June 30, 2009	11,828	37.59	—	—
Total	37,901	$ 37.15	—	—

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

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

At our May 7, 2009 annual meeting of stockholders, our stockholders elected all of our 13 nominees for director, approved the Newfield Exploration Company 2009 Omnibus Stock Plan and the Newfield Exploration Company 2009 Non-Employee Director Restricted Stock Plan, and ratified the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2009 by the following votes:

1. Election of Directors:

Nominee	For	Against	Abstain
David A. Trice	112,326,771	8,696,998	102,781
Lee K. Boothby	117,728,685	3,300,992	96,872
Philip J. Burguieres	82,134,324	38,855,442	136,783
Pamela J. Gardner	115,958,891	5,040,738	126,920
Dennis R. Hendrix	81,998,177	38,985,135	143,237
John Randolph Kemp III	82,136,627	38,856,269	133,653
J. Michael Lacey	82,147,550	38,853,408	125,591
Joseph H. Netherland	82,132,064	38,852,134	142,352
Howard H. Newman	112,765,078	8,247,117	114,354
Thomas G. Ricks	113,291,163	7,714,280	121,107
Juanita F. Romans	115,947,985	5,057,078	121,487
C. E. (Chuck) Shultz	74,843,324	44,321,690	1,961,536
J. Terry Strange	108,689,052	10,496,983	1,940,515

2. Approval of the Newfield Exploration Company 2009 Omnibus Stock Plan:

For:	106,902,365
Against:	6,957,521
Abstentions:	42,551
Broker Non-Votes:	7,224,113

3. Approval of the Newfield Exploration Company 2009 Non-Employee Director Restricted Stock Plan:

For:	111,540,950
Against:	2,312,569
Abstentions:	48,919
Broker Non-Votes:	7,224,112

4. Ratification of Appointment of Independent Registered Public Accounting Firm:

For:	117,607,783
Against:	3,449,292
Abstentions:	69,474
Broker Non-Votes:	0

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Item 6. Exhibits

Exhibit Number	Description
10.23†	Retirement Agreement—David A. Trice (with form of Restricted Stock Unit Award Agreement and form of Non-Compete Agreement attached thereto) (incorporated by reference to Exhibit 10.23 to Newfield's Current Report on Form 8-K filed with the SEC on April 22, 2009)
10.24†	Form of Restricted Stock Unit Award Agreement—Lee K. Boothby and Gary D. Packer (incorporated by reference to Exhibit 10.24 to Newfield's Current Report on Form 8-K filed with the SEC on May 11, 2009)
10.25†	Newfield Exploration Company 2009 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield's Registration Statement on Form S-8 (Reg. No. 333-158961) filed with the SEC on May 4, 2009)
10.26†	Newfield Exploration Company 2009 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 99.2 to Newfield's Registration Statement on Form S-8 (Reg. No. 333-158961) filed with the SEC on May 4, 2009)
10.27†*	Form of Restricted Stock Unit Award Agreement—Daryll T. Howard and Samuel E. Langford
31.1*	Certification of Chief Executive Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101**	Interactive Data File

† Identifies management contracts and compensatory plans or arrangements.
* Filed or furnished herewith.
** To be furnished by amendment to this report.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NEWFIELD EXPLORATION COMPANY

Date: July 24, 2009	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer

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Exhibit Index

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