NEWFIELD EXPLORATION CO /DE/
Form 10-Q
October 23, 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 September 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	72-1133047
(State or other jurisdiction of incorporation or organization)	(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 þ 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 October 22, 2009, there were 132,868,433 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)

	September 30, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$96	$24
Accounts receivable	293	375
Inventories	110	96
Derivative assets	377	663
Other current assets	66	48
Total current assets	942	1,206
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,265 at September 30, 2009 and $1,303 at December 31, 2008 were excluded from amortization)	9,960	10,349
Less—accumulated depreciation, depletion and amortization	(5,020)	(4,591)
Total property and equipment, net	4,940	5,758
Derivative assets	48	247
Long-term investments	56	72
Deferred taxes	36	¾
Other assets	15	22
Total assets	$6,037	$7,305
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$34	$103
Accrued liabilities	566	672
Advances from joint owners	74	73
Asset retirement obligation	6	11
Deferred taxes	125	226
Total current liabilities	805	1,085
Other liabilities	41	22
Derivative liabilities	25	¾
Long-term debt	2,106	2,213
Asset retirement obligation	77	70
Deferred taxes	345	658
Total long-term liabilities	2,594	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
	1	1

Common stock ($0.01 par value; 200,000,000 shares authorized at September 30, 2009 and December 31, 2008; 134,338,720 and 133,985,751 shares issued at September 30, 2009 and December 31, 2008, respectively)		
Additional paid-in capital	1,375	1,335
Treasury stock (at cost; 1,492,640 and 1,908,243 shares at September 30, 2009 and December 31, 2008, respectively)	(33)	(32)
Accumulated other comprehensive income (loss):		
Unrealized loss on investments	(13)	(13)
Unrealized gain (loss) on post retirement benefits	(1)	2
Retained earnings	1,309	1,964
Total stockholders' equity	2,638	3,257
Total liabilities and stockholders' equity	$6,037	$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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Oil and gas revenues	$375	$680	$924	$1,887
Operating expenses:				
Lease operating	64	67	192	184
Production and other taxes	14	51	38	154
Depreciation, depletion and amortization	144	181	440	504
General and administrative	40	36	106	105
Ceiling test writedown	¾	¾	1,344	¾
Other	1	¾	8	¾
Total operating expenses	263	335	2,128	947
Income (loss) from operations	112	345	(1,204)	940
Other income (expenses):				
Interest expense	(31)	(36)	(95)	(83)
Capitalized interest	13	16	39	43
Commodity derivative income (expense)	(8)	726	189	(247)
Other	(1)	8	4	10
Total other income (expenses)	(27)	714	137	(277)
Income (loss) before income taxes	85	1,059	(1,067)	663
Income tax provision (benefit):				
Current	35	9	36	34
Deferred	(28)	326	(448)	213
Total income tax provision (benefit)	7	335	(412)	247
Net income (loss)	$78	$724	$(655)	$416
Income (loss) per share:				
Basic	$0.59	$5.59	$(5.06)	$3.22
Diluted	$0.58	$5.48	$(5.06)	$3.15
Weighted average number of shares outstanding for basic income (loss) per share	130	129	129	129
Weighted average number of shares outstanding for diluted income (loss) per share	132	132	129	132

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

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flows from operating activities:		
Net income (loss)	$(655)	$416
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	440	504
Deferred tax provision (benefit)	(448)	213
Stock-based compensation	22	17
Ceiling test writedown	1,344	
Commodity derivative (income) expense	(189)	247
Cash receipts (payments) on derivative settlements	701	(783)
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	81	(63)
Increase in inventories	(22)	(5)
Increase in commodity derivative assets		(65)
Increase in other current assets	(18)	(10)
Increase (decrease) in accounts payable and accrued liabilities	(59)	135
Increase (decrease) in advances from joint owners	1	2
Increase in other liabilities	19	14
Net cash provided by operating activities	1,217	622
Cash flows from investing activities:		
Additions to oil and gas properties	(1,045)	(1,537)
Acquisition of oil and gas properties	(9)	(231)
Proceeds from sale of oil and gas properties		2
Additions to furniture, fixtures and equipment	(7)	(14)
Purchases of investments		(22)
Redemptions of investments	18	70
Net cash used in investing activities	(1,043)	(1,732)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	813	1,826
Repayments of borrowings under credit arrangements	(920)	(1,541)
Net proceeds from issuance of senior subordinated notes		592
Proceeds from issuances of common stock	6	18
Purchases of treasury stock, net	(1)	
Net cash provided by (used in) financing activities	(102)	895
Increase (decrease) in cash and cash equivalents	72	(215)
Cash and cash equivalents, beginning of period	24	250
Cash and cash equivalents, end of period	$96	$35

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	Total Stockholders'
	Shares	Amount	Shares	Amount	Capital	Earnings	(Loss)	Equity
Balance, December 31, 2008	134.0	$ 1	(1.9)	$ (32)	$ 1,335	$ 1,964	$ (11)	$ 3,257
Issuances of common and restricted stock	0.3				6			6
Treasury stock, at cost			0.4	(1)				(1)
Stock-based compensation					34			34
Comprehensive loss:								
Net loss						(655)		(655)
Realized loss on post retirement benefits, net of tax of $2							(3)	(3)
Total comprehensive loss								(658)
Balance, September 30, 2009	134.3	$ 1	(1.5)	$ (33)	$ 1,375	$ 1,309	$ (14)	$ 2,638

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 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 September 30, 2009 and 2008 of $0.5 million and $1 million, respectively, and for the nine months ended September 30, 2009 and 2008 of $2 million and $3 million, respectively.

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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 197,000 barrels and 293,000 barrels of crude oil valued at cost of $6 million and $9 million at September 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 September 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.

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 nine months ended September 30, 2009 are set forth below (in millions):

Balance as of January 1, 2009	$	81
Accretion expense		4
Additions		8
Settlements		(10)
Balance at September 30, 2009	$	83
Less: Current portion of ARO at September 30, 2009		(6)
Total long-term ARO at September 30, 2009	$	77

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.

During the third quarter of 2009, there was no change to our liability of $1 million for uncertain tax positions. As of September 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. We anticipate that this audit should be completed by December 31, 2009.

Derivative Financial Instruments

Authoritative accounting and reporting guidance requires that every derivative instrument be recorded on the balance sheet at its fair value and 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 the accounting guidance, 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 October 22, 2009, the day prior to issuing these financial statements, we completed our review and analysis of potential subsequent events and none were identified.

New Accounting Requirements

In September 2006, the Financial Accounting Standards Board (FASB) defined fair value, established criteria to be considered when measuring fair value and expanded disclosures about fair value measurements. The guidance 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 for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB issued additional authoritative guidance, which granted a one-year deferral of the effective date 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 the provisions to non-financial assets and liabilities. The adoption did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued guidance requiring enhanced disclosures about our derivative and hedging activities that is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements beginning January 1, 2009. Please see Note 7, "Derivative Financial Instruments – Additional Disclosures about Derivative Instruments and Hedging Activities." The adoption did not have an impact on our financial position or results of operations.

In April 2009, the FASB issued additional guidance regarding fair value measurements and impairments of securities which makes fair value measurements more consistent with fair value principles, enhances consistency in financial reporting by increasing the frequency of fair value disclosures, and provides greater clarity and consistency in accounting for and presenting impairment losses on securities. The additional guidance is 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 for the period ending March 31, 2009. The adoption did not have a material impact on our financial position or results of operations.

In May 2009, the FASB established 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 guidance is based on the same principles as those that previously existed. This guidance, 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. Our adoption of these provisions beginning with the period ending June 30, 2009 did not have an impact on our financial position or results of operations.

In September 2009, the FASB issued its proposed updates to oil and gas accounting rules to align the oil and gas reserve estimation and disclosure requirements of Extractive Industries—Oil and Gas (Topic 932) with the requirements in the Securities and Exchange Commission's final rule, Modernization of the Oil and Gas Reporting Requirements, which was issued on December 31, 2008 and is effective for the year ended December 31, 2009. The public comment period for the FASB's proposed updates ended October 15, 2009; however, no final guidance has been issued by the FASB. We are evaluating the potential impact of any updates to the oil and gas accounting rules and will comply with any new accounting and disclosure requirements once they become effective.

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 stock 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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(In millions, except per share data)			
Income (numerator):				
Net income (loss) – basic and diluted	$78	$724	$(655)	$416
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)	2	3		3
Weighted average shares — diluted	132	132	129	132
Income (loss) per share:				
Basic	$0.59	$5.59	$(5.06)	$3.22
Diluted	$0.58	$5.48	$(5.06)	$3.15

(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 nine months ended September 30, 2009 as their effect would have been anti-dilutive. Had we recognized net income for this period, 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.

3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	September 30, 2009	December 31, 2008
	(In millions)	
Oil and Gas Properties:		
Subject to amortization	$8,604	$8,961
Not subject to amortization:		
Exploration in progress	271	207
Development in progress	65	71
Capitalized interest	136	129
Fee mineral interests	23	23

Other capital costs:		
Incurred in 2009	55	
Incurred in 2008	222	328
Incurred in 2007	213	242
Incurred in 2006 and prior	280	303
Total not subject to amortization	1,265	1,303
Gross oil and gas properties	9,869	10,264
Accumulated depreciation, depletion and amortization	(4,971)	(4,550)
Net oil and gas properties	4,898	5,714
Other property and equipment	91	85
Accumulated depreciation and amortization	(49)	(41)
Net other property and equipment	42	44
Property and equipment, net	$4,940	$5,758

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

4. Debt:

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

	September 30, 2009	December 31, 2008
	(In millions)	
Senior unsecured debt:		
Revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans	454	514
Total revolving credit facility	454	514
Money market lines of credit (1)		47
Total credit arrangements	454	561
7 5/8% Senior Notes due 2011	175	175
Fair value of interest rate swap (2)	2	2
Total senior unsecured notes	177	177
Total senior unsecured debt	631	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	$2,106	$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 September 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 September 30, 2009).

We pay commitment fees on available but undrawn amounts based on a grid of our debt rating (0.175% per annum at September 30, 2009). We incurred fees under this arrangement of approximately $0.3 million and $1 million for the three and nine months ended September 30, 2009, respectively, which are recorded in interest expense on our consolidated statement of income. For the three and nine months ended September 30, 2008, we incurred commitment fees of approximately $0.4 million and $1 million, respectively.

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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 September 30, 2009 we were in compliance with all of our debt covenants.

As of September 30, 2009, we had $16 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 September 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 financial institutions, the availability of which is at the discretion of the financial institution.

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 our geographic operating segment information as of and for the three and nine months ended September 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 (In millions)	Other International	Total
Three Months Ended September 30, 2009:					
Oil and gas revenues	$231	$132	$12	$ ¾	$375
Operating expenses:					
Lease operating	48	15	1	¾	64
Production and other taxes	5	8	1	¾	14
Depreciation, depletion and amortization	100	41	3	¾	144
General and administrative	39	1	¾	¾	40
Other	1	¾	¾	¾	1
Allocated income taxes	14	26	2	¾	
Net income from oil and gas properties	$24	$41	$5	$ ¾	
Total operating expenses					263
Income from operations					112
Interest expense, net of interest income, capitalized interest and other					(19)
Commodity derivative expense					(8)
Income before income taxes					$85
Total long-lived assets	$4,393	$353	$149	$ 3	$4,898
Additions to long-lived assets	$245	$16	$24	$ ¾	$285

	United States	Malaysia	China (In millions)	Other International	Total
Three Months Ended September 30, 2008:					
Oil and gas revenues	$560	$103	$17	$ ¾	$680
Operating expenses:					
Lease operating	54	13	¾	¾	67
Production and other taxes	21	27	3	¾	51
Depreciation, depletion and amortization	154	24	3	¾	181
General and administrative	35	1	¾	¾	36
Allocated income taxes	113	15	2	¾	
Net income from oil and gas properties	$183	$23	$9	$ ¾	
Total operating expenses					335
Income from operations					345
Interest expense, net of interest income, capitalized interest and other					(12)

Commodity derivative income					726
Income before income taxes					$1,059
Total long-lived assets	$6,629	$442	$107	$ 2	$7,180
Additions to long-lived assets	$462	$45	$7	$ ¾	$514

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

	United States	Malaysia	China (In millions)	Other International	Total
Nine Months Ended September 30, 2009:					
Oil and gas revenues	$667	$226	$31	$ ¾	$924
Operating expenses:					
Lease operating	152	36	4	¾	192
Production and other taxes	23	13	2	¾	38
Depreciation, depletion and amortization	344	86	10	¾	440
General and administrative	103	2	1	¾	106
Ceiling test writedown	1,344	¾	¾	¾	1,344
Other	8	¾	¾	¾	8
Allocated income taxes	(471)	34	3	¾	
Net income (loss) from oil and gas properties	$(836)	$55	$11	$ ¾	
Total operating expenses					2,128
Loss from operations					(1,204)
Interest expense, net of interest income, capitalized interest and other					(52)
Commodity derivative income					189
Loss before income taxes					$(1,067)
Total long-lived assets	$4,393	$353	$149	$ 3	$4,898
Additions to long-lived assets	$860	$44	$50	$ ¾	$954

	United States	Malaysia	China (In millions)	Other International	Total
Nine Months Ended September 30, 2008:					
Oil and gas revenues	$1,589	$246	$52	$ ¾	$1,887
Operating expenses:					
Lease operating	147	35	2	¾	184
Production and other taxes	64	79	11	¾	154
Depreciation, depletion and amortization	438	57	9	¾	504
General and administrative	101	2	2	¾	105
Allocated income taxes	319	28	7	¾	
Net income from oil and gas properties	$520	$45	$21	$ ¾	
Total operating expenses					947
Income from operations					940
Interest expense, net of interest income,					(30)

capitalized interest and other					
Commodity derivative expense					(247)
Income before income taxes					$663
Total long-lived assets	$6,629	$442	$107	$ 2	$7,180
Additions to long-lived assets	$1,587	$132	$38	$ 1	$1,758

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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 September 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					
			Collars				Estimated Fair Value Asset
		Swaps	Floors		Ceilings		
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	(Liability) (In millions)
October 2009 – December 2009							
Price swap contracts	26,120	$ 7.34	¾	¾	¾	¾	$ 64
Collar contracts	8,435	—	$8.00 – $8.50	$ 8.23	$8.97 – $14.37	$ 11.20	31
January 2010 – March 2010							
Price swap contracts	31,800	6.79	¾	¾	¾	¾	26
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	16
July 2010 – September 2010							
Price swap contracts	35,200	6.41	¾	¾	¾	¾	8
October 2010 – December 2010							
Price swap contracts	28,320	6.49	¾	¾	¾	¾	(6)
January 2011 – March 2011							
Price swap contracts	18,900	6.55	¾	¾	¾	¾	(12)
April 2011 – June 2011							
Price swap contracts	19,110	6.55	¾	¾	¾	¾	1
July 2011 – September 2011							
Price swap contracts	19,320	6.55	¾	¾	¾	¾	(2)
October 2011							
Price swap contracts	6,510	6.55	¾	¾	¾	¾	(2)
							$ 139

Oil

Period and Type of Contract	Volume in MBbls	Swaps (Weighted Average)	Additional Put Range	Additional Put Weighted Average	NYMEX Contract Price Per Bbl Collars Floors Range	Floors Weighted Average	Ceilings Range	Ceilings Weighted Average	Floors Range	Floors Weig Ave
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	$10
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 September 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 and Mid-Continent, as set forth in the table below.

	Rocky Mountains		Mid-Continent		Estimated
	Volume in MMBtus	Weighted Average Differential	Volume in MMBtus	Weighted Average Differential	Fair Value Asset (Liability) (In millions)
October 2009 – December 2009	1,380	$(1.05)	1,840	$(0.55)	$(1)
January 2010 – December 2010	5,520	$(0.99)	7,300	$(0.55)	(4)
January 2011 – December 2011	5,280	$(0.95)	10,350	$(0.55)	(1)
January 2012 – December 2012	4,920	$(0.91)	18,300	$(0.55)	(1)
					$(7)

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. 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 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 September 30, 2009, we had derivative financial instruments recorded in our balance sheet as set forth below.

Type of Contract	Balance Sheet Location	Estimated Fair Value (In millions)
Derivatives not designated as hedging instruments:		
Natural gas contracts	Derivative assets – current	$ 160
Oil contracts	Derivative assets – current	219
Basis contracts	Derivative assets – current	(4)
Natural gas contracts	Derivative assets – noncurrent	1
Oil contracts	Derivative assets – noncurrent	47
Natural gas contracts	Derivative liabilities – noncurrent	(22)
Basis contracts	Derivative liabilities – noncurrent	(3)
Total derivatives not designated as hedging instruments		398
Derivative designated as a fair value hedge:		
Interest rate swap	Derivative assets – current	2
Total derivative designated as a hedging instrument		2
Net derivative assets		$ 400

The amount of gain (loss) recognized in income related to our derivative financial instruments for the indicated periods was as follows:

Type of Contract	Location of Gain/(Loss) Recognized in Income	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Commodity derivative income (expense)	$ (16)	$ 278
Oil contracts	Commodity derivative income (expense)	15	(64)
Basis contracts	Commodity derivative income (expense)	(7)	(25)
Derivative designated as a fair value hedge:			
Interest rate swap	Interest expense		1
Total		$ (8)	$ 190

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NEWFIELD EXPLORATION COMPANY
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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 September 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 82% of our future hedged production, the largest of which was J Aron & Company and accounts for 26% 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:

	September 30, 2009	December 31, 2008
	(In millions)	
Revenue	$ 157	$ 157
Joint interest	114	197
Other	28	26
Reserve for doubtful accounts	(6)	(5)
Total accounts receivable	$ 293	$ 375

9. Accrued Liabilities:

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

	September 30, 2009	December 31, 2008
	(In millions)	
Revenue payable	$ 73	$ 75
Accrued capital costs	202	319
Accrued lease operating expenses	49	50
Employee incentive expense	58	73
Accrued interest on long-term debt	36	25
Taxes payable	94	69
Other	54	61
Total accrued liabilities	$ 566	$ 672

10. Comprehensive Income (Loss):

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Net income (loss)	$ 78	$ 724	$ (655)	$ 416
Unrealized loss on investments, net of tax of $1 and $3 for the three and nine months ended September 30, 2008, respectively		(3)		(7)
Realized loss on post retirement benefits, net of tax of $2	(3)		(3)	
Total comprehensive income (loss)	$ 75	$ 721	$ (658)	$ 409

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

11. Stock-Based Compensation:

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. 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 stock and restricted stock 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 September 30, 2009, we had approximately 2.5 million additional shares available for issuance pursuant to our existing employee and director plans. Of these shares, 1.7 million could be granted as restricted stock or restricted stock units.

For the three month periods ended September 30, 2009 and 2008, we recorded stock-based compensation expense of $11 million and $9 million, respectively, for all plans. Of these amounts, $4 million and $2 million, respectively, were capitalized in oil and gas properties.

For the nine month periods ended September 30, 2009 and 2008, we recorded stock-based compensation expense of $34 million and $26 million, respectively, for all plans. Of these amounts, $12 million and $7 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 nine months ended September 30, 2009 or 2008 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.

As of September 30, 2009, we had approximately $63 million of total unrecognized stock-based 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 nine months ended September 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	(0.3)	20.47			
Forfeited	(0.1)	38.80			
Outstanding at September 30, 2009	3.1	$ 29.45		4.9	$ 43.3
Exercisable at September 30, 2009	2.5	$ 26.21		4.3	$ 41.1

(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 September 30, 2009, the last reported sales price of our common stock on the New York Stock Exchange was $42.56 per share.

The following table summarizes information about stock options outstanding and exercisable at September 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	0.4	$ 14.91	0.1	$ 14.91
15.01 to 17.50	0.6	2.8	16.63	0.6	16.63
17.51 to 22.50	0.4	2.5	18.87	0.4	18.87
22.51 to 27.50	0.4	4.4	24.77	0.4	24.77
27.51 to 35.00	0.9	5.3	31.21	0.7	31.07
35.01 to 41.72	0.1	5.6	37.49	0.1	37.45
	0.6	8.4	48.45	0.2	48.45

41.73 to 48.45							
	3.1	4.9	$	29.45	2.5	$	26.21

Restricted Shares. At September 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 September 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 authoritative accounting guidance).

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NEWFIELD EXPLORATION COMPANY
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The following table provides information about restricted share and restricted share unit activity for the nine months ended September 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	1,071		1,071	23.01
Forfeited	(55)	(316)	(371)	26.53
Vested	(253)	(110)	(363)	35.53
Non-vested shares outstanding at September 30, 2009	2,442	782	3,224	$ 31.56

The total fair value of restricted shares that vested during the nine months ended September 30, 2009 was $13 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 first nine months of 2009, options to purchase 144,291 shares of our common stock were issued under the plan. The weighted average fair value of each option was $9.02 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 0.29%, an expected life of six months and weighted average volatility of 80%. At September 30, 2009, 409,564 shares of our common stock remained available for issuance under the plan.

12. Income Taxes:

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			

Amount computed using the statutory rate	$ 30	$ 371	$ (374)	$ 232
Increase (decrease) in taxes resulting from:				
State and local income taxes, net of federal effect		(36)	(17)	13
Net effect of different tax rates in non-U.S. jurisdictions	1		2	1
Valuation allowance	(24)		(24)	
Other			1	1
Total income tax provision (benefit)	$ 7	$ 335	$ (412)	$ 247

In the third quarter of 2009, we reversed the valuation allowance related to the deferred tax asset associated with our fourth quarter 2008 ceiling test writedown in Malaysia. The valuation allowance was reversed as a result of a substantial increase in our estimate of future taxable income in Malaysia due to increases in current and future anticipated crude oil prices.

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As of September 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 because we do not anticipate that we will have sufficient estimated future taxable income in the appropriate jurisdictions. Therefore, a valuation allowance has been established for this item. 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:

Effective January 1, 2008, we adopted the authoritative guidance that applies to all financial assets and liabilities required to be measured and reported on a fair value basis. Beginning January 1, 2009, we also applied the guidance to non-financial assets and liabilities. 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). The guidance requires disclosure that establishes a framework for measuring fair value, expands disclosure about fair value measurements and 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.

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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Fair Value of Derivative Instruments

The following table summarizes the valuation of our investments and financial instruments by pricing levels as of September 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	$ 9	$	$	$ 9
Auction rate securities			41	41
Oil and gas derivative swap contracts		149		149
Oil and gas derivative option contracts			249	249
Interest rate swap		2		2
Total	$ 9	$ 151	$ 290	$ 450

The determination of the fair values above incorporates various factors which 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 September 30, 2009, we continued to hold $41 million of auction rate securities maturing 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 $18 million ($12 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 table sets 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		(23)	(23)
Included in other comprehensive income (loss)			
Purchases, issuances and settlements	(18)	(270)	(288)
Transfers in and out of Level 3			
Balance at September 30, 2009	$41	$249	$290
Change in unrealized gains (losses) relating to			
investments and derivatives still held at September 30, 2009	$	$(70)	$(70)

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Fair Value of Debt

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

7 5/8% Senior Notes due 2011	$182
6 5/8% Senior Subordinated Notes due 2014	321
6 5/8% Senior Subordinated Notes due 2016	540
7 1/8% Senior Subordinated Notes due 2018	603

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

14. Pension Plan Obligation:

As a result of our acquisition of EEX Corporation in November 2002, we assumed responsibility for a defined benefit pension plan for current and former employees of EEX and its subsidiaries. The plan was amended, effective March 31, 2003, to cease all future retirement benefit accruals. We filed for a standard termination with a proposed plan termination date of April 30, 2008. A favorable determination letter was received on March 16, 2009 from the Internal Revenue Service. During the third quarter of 2009, we completed the final settlement of the plan and recorded general and administrative expense of $2 million associated with changes in the pension liability due to actual plan termination costs.

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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 September 30, 2009, we had net derivative assets of $400 million, of which 62% 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 our quarterly report on Form 10-Q for the quarter ended June 30, 2009 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 September 30, 2009 are designated for hedge accounting and the settlement of all oil and gas hedging contracts during the third quarter and first nine 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 $375 million for the third quarter of 2009 were 45% lower than the comparable period of 2008 due to significantly lower average realized oil and natural gas prices and lower natural gas production partially offset by higher oil production. Revenues of $924 million for the first nine months of 2009 were 51% lower than the comparable period of 2008 due to significantly lower average realized oil and natural gas prices partially offset by higher oil and natural gas production.

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	Three Months Ended September 30, 2009	2008	Percentage Increase (Decrease)	Nine Months Ended September 30, 2009	2008	Percentage Increase (Decrease)
Production (1):						
Domestic:						
Natural gas (Bcf)	42.5	44.9	(5)%	132.6	129.0	3 %
Oil and condensate (MBbls)	1,675	1,617	4 %	5,312	4,567	16 %
Total (Bcfe)	52.6	54.7	(4)%	164.4	156.4	5 %
International:						
Natural gas (Bcf)	—	—	—	—	—	—
Oil and condensate (MBbls)	2,151	1,124	92 %	4,717	2,954	60 %
Total (Bcfe)	12.9	6.7	92 %	28.3	17.7	60 %
Total:						
Natural gas (Bcf)	42.5	44.9	(5)%	132.6	129.0	3 %
Oil and condensate (MBbls)	3,826	2,741	40 %	10,029	7,521	33 %
Total (Bcfe)	65.5	61.4	7 %	192.7	174.1	11 %
Average Realized Prices (2):						
Domestic:						
Natural gas (per Mcf)	$ 3.14	$ 8.67	(64)%	$ 3.16	$ 8.72	(64)%
Oil and condensate (per Bbl)	57.54	105.46	(45)%	46.21	100.91	(54)%
Natural gas equivalent (per Mcfe)	4.38	10.25	(57)%	4.04	10.14	(60)%
International:						
Natural gas (per Mcf)	$ —	$ —	—	$ —	$ —	—
Oil and condensate (per Bbl)	66.76	106.87	(38)%	54.45	100.93	(46)%
Natural gas equivalent (per Mcfe)	11.13	17.81	(38)%	9.08	16.82	(46)%
Total:						
Natural gas (per Mcf)	$ 3.14	$ 8.67	(64)%	$ 3.16	$ 8.72	(64)%
Oil and condensate (per Bbl)	62.72	106.04	(41)%	50.08	100.92	(50)%
Natural gas equivalent (per Mcfe)	5.71	11.08	(48)%	4.78	10.82	(56)%

(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 natural gas would have been $6.88 and $7.25 per Mcf for the three months ended September 30, 2009 and 2008, respectively, and $6.18 and $7.69 per Mcf for the nine months ended September 30, 2009 and 2008, respectively. Our total oil and condensate average realized price would have been $82.61 and $85.44 per Bbl for

the three months ended September 30, 2009 and 2008, respectively, and $78.07 and $80.12 per Bbl for the nine months ended September 30, 2009 and 2008, respectively. All amounts for the nine months ended September 30, 2008 exclude the cash payments to reset our 2009 and 2010 crude oil hedges of $502 million.

Domestic Production. Our domestic oil and gas production, stated on a natural gas equivalent basis, for the three months ended September 30, 2009 decreased over the comparable period of 2008 primarily due to the voluntary curtailment of approximately 3 Bcfe from our Mid-Continent division due to low natural gas prices and natural field declines.

Our domestic oil and gas production, stated on a natural gas equivalent basis, for the nine months ended September 30, 2009 increased over the comparable period of 2008 primarily due to increased production in our Mid-Continent division as a result of continued successful drilling efforts, partially offset by natural field declines and the voluntary curtailment of approximately 3 Bcfe during the third quarter of 2009 from our Mid-Continent division due to low natural gas prices.

International Production. Our international oil production, stated on a natural gas equivalent basis, for the three and nine months ended September 30, 2009 increased over the comparable periods of 2008 primarily due to the new field developments on PM 323 and PM 318 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 September 30, 2009 and 2008.

	Unit-of-Production			Total Amount		
	Three Months Ended September 30,		Percentage Increase (Decrease)	Three Months Ended September 30,		Percentage Increase (Decrease)
	2009	2008		2009	2008	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 0.92	$ 0.99	(7)%	$ 48	$ 54	(11)%
Production and other taxes	0.09	0.38	(76)%	5	21	(77)%
Depreciation, depletion and amortization	1.91	2.81	(32)%	100	154	(35)%
General and administrative	0.73	0.63	16 %	39	35	11 %
Other	0.02	—	100 %	1	—	100 %
Total operating expenses	3.67	4.81	(24)%	193	264	(27)%
International:						
Lease operating	$ 1.23	$ 1.94	(37)%	$ 16	$ 13	22 %
Production and other taxes	0.72	4.46	(84)%	9	30	(69)%
Depreciation, depletion and amortization	3.37	3.95	(15)%	44	27	63 %
General and administrative	0.11	0.23	(52)%	1	1	(10)%
Total operating expenses	5.43	10.58	(49)%	70	71	(2)%
Total:						
Lease operating	$ 0.98	$ 1.10	(11)%	$ 64	$ 67	(5)%
Production and other taxes	0.21	0.82	(74)%	14	51	(72)%
Depreciation, depletion and amortization	2.20	2.94	(25)%	144	181	(20)%
General and administrative	0.61	0.59	3 %	40	36	10 %
Other	0.02	—	100 %	1	—	100 %
Total operating expenses	4.02	5.45	(26)%	263	335	(21)%

Domestic Operations. Our domestic operating expenses, stated on a Mcfe basis, for the three months ended September 30, 2009 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 7% primarily due to lower operating and service costs. This decrease in LOE was partially offset by decreased production resulting from the voluntary curtailment of approximately 3 Bcfe of production from our Mid-Continent division.

- Production and other taxes per Mcfe decreased 76% primarily due to significantly lower realized commodity prices during the third quarter of 2009 compared to the same period of 2008.

- Our depreciation, depletion and amortization (DD&A) rate per Mcfe decreased 32% 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 increased 16% primarily due to increased employee-related expenses associated with our growing domestic workforce and the expense associated with the settlement of the pension plan obligation we assumed with our acquisition of EEX Corporation in November 2002, partially offset by a 21% increase in our capitalized direct internal costs. During the third quarter of 2009, we capitalized $16 million of direct internal costs as compared to $13 million in the third quarter of 2008.

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International Operations. Our international operating expenses, stated on a Mcfe basis, for the three months ended September 30, 2009 decreased 49% over the same period of 2008. The components of the period to period change are as follows:

- LOE per Mcfe decreased 37% while total LOE increased 22% period over period. The decrease in LOE per Mcfe is primarily due to increased production volumes and lower operating and service costs. Total LOE increased due to the new field development on PM 318 in Malaysia, partially offset by lower operating and service costs.

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

- Total DD&A expense increased 63% primarily due to the timing of liftings and the additional production volumes associated with the new field development on PM 318 in Malaysia, partially offset by a decrease in the DD&A rate due to reserve additions in Malaysia in the first quarter of 2009.

- G&A expense decreased $0.12 per Mcfe primarily due to the 92% increase in production volumes period over period.

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

	Unit-of-Production			Total Amount		
	Nine Months Ended September 30,		Percentage Increase (Decrease)	Nine Months Ended September 30,		Percentage Increase (Decrease)
	2009	2008		2009	2008	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 0.92	$ 0.94	(2)%	$ 152	$ 147	3 %
Production and other taxes	0.14	0.41	(66)%	23	64	(64)%
Depreciation, depletion and amortization	2.09	2.80	(25)%	344	438	(21)%
General and administrative	0.62	0.65	(5)%	103	101	1 %
Ceiling test writedown	8.18	—	100 %	1,344	—	100 %
Other	0.05	—	100 %	8	—	100 %
Total operating expenses	12.00	4.80	150 %	1,974	750	163 %
International:						
Lease operating	$ 1.42	$ 2.10	(32)%	$ 40	$ 37	8 %
Production and other taxes	0.51	5.05	(90)%	15	90	(84)%
Depreciation, depletion and amortization	3.38	3.72	(9)%	96	66	45 %
General and administrative	0.12	0.21	(43)%	3	4	(6)%
Total operating expenses	5.43	11.08	(51)%	154	197	(22)%
Total:						
Lease operating	$ 1.00	$ 1.06	(6)%	$ 192	$ 184	4 %
Production and other taxes	0.20	0.88	(77)%	38	154	(76)%
Depreciation, depletion and amortization	2.28	2.89	(21)%	440	504	(13)%
General and administrative	0.55	0.60	(8)%	106	105	1 %

Ceiling test writedown	6.98	—	100 %	1,344	—	100 %
Other	0.04	—	100 %	8	—	100 %
Total operating expenses	11.05	5.43	103 %	2,128	947	125 %

Domestic Operations. Our domestic operating expenses, stated on a Mcfe basis, for the nine months ended September 30, 2009 increased 150% 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 decreased 2% while total LOE increased 3% period over period. The decrease in LOE per Mcfe is primarily due to the 5% increase in production volumes period over period. Total LOE increased due to increased well workover activity associated with our onshore Texas and deepwater Gulf of Mexico operations, partially offset by overall lower operating and service costs.

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- Production and other taxes per Mcfe decreased 66% primarily due to significantly lower realized commodity prices during the first nine months of 2009 compared to the same period of 2008. We received refunds of $16 million ($0.09 per Mcfe) during the first nine months of 2009 related to production tax exemptions on some of our onshore wells compared to similar refunds of $20 million ($0.13 per Mcfe) during the same period of 2008.

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

- G&A expense per Mcfe decreased 5% while total G&A expense increased slightly. The decrease per Mcfe is primarily due to the 5% increase in production volumes period over period. The slight increase in total G&A is primarily due to increased employee-related expenses associated with our growing domestic workforce offset by a decrease in incentive compensation expense, which is calculated based on adjusted net income (as defined in our incentive 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. Capitalized direct internal costs for the nine months ended September 30, 2009 increased 18% to $44 million, from $37 million for the same period of 2008.

- We recorded a ceiling test writedown of $1.3 billion ($8.18 per Mcfe) due to significantly lower natural gas prices at March 31, 2009.

International Operations. Our international operating expenses, stated on a Mcfe basis, for the nine months ended September 30, 2009 decreased 51% over the same period of 2008. The period to period change was primarily related to the following items:

- LOE per Mcfe decreased 32% while total LOE increased slightly period over period. The decrease in LOE per Mcfe is primarily due to increased production volumes associated with the new field developments on PM 318 and PM 323 in Malaysia and lower operating and service costs.

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

- Total DD&A expense increased 45% primarily due to the timing of liftings and the additional production volumes associated with the new field development on PM 318 in Malaysia, partially offset by a decrease in the DD&A rate due to reserve additions in Malaysia in the first quarter of 2009.

- G&A expense per Mcfe decreased $0.09 primarily due to the 60% increase in production volumes period over period.

Commodity Derivative Income (Expense)

The significant fluctuation in commodity derivative income (expense) 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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(In millions)			
Gross interest expense:				
Credit arrangements	$ 2	$ 7	$ 7	$ 10
Senior notes	3	3	9	10
Senior subordinated notes	26	26	77	61
Other	—	—	2	2
Total gross interest expense	31	36	95	83
Capitalized interest	(13)	(16)	(39)	(43)
Net interest expense	$ 18	$ 20	$ 56	$ 40

The 13% decrease in gross interest expense for the third quarter of 2009 as compared to the same period of 2008 resulted from lower average outstanding borrowings during 2009. The 15% increase in gross interest expense for the nine months ended September 30, 2009 as compared to the same period of 2008 resulted 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 third quarter of 2009 and 2008 were 8.6% and 31.7%, respectively. The effective tax rates for the first nine months of 2009 and 2008 were 38.6% and 37.3%, respectively. The decrease in our effective tax rate for the third quarter of 2009 as compared to the comparable period of 2008 was due to the reversal of the valuation allowance related to the deferred tax asset associated with our fourth quarter 2008 ceiling test writedown in Malaysia. The valuation allowance was reversed as a result of a substantial increase in our estimate of future taxable income in Malaysia due to increases in current and future anticipated crude oil prices. 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.

We establish a capital budget at the beginning of each calendar year. In light of the economic outlook and commodity price environment, we limited our 2009 capital expenditures to a level that we expect can be funded with cash flows from operations, thereby preserving liquidity under our credit arrangements. Continuing to be mindful of anticipated future cash flows from operations, we currently are developing our 2010 capital budget. Our 2009 capital budget focuses on those projects that we believe will generate and lay the foundation for production growth and our 2010 capital budget will have a similar emphasis. The timing of our capital expenditures and the receipt of cash flows do not necessarily match, and we anticipate that we will continue to borrow and repay funds under our credit arrangements during these periods. 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. We have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

We continue to hold auction rate securities with a fair value of $41 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 September 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 October 21, 2009, we had $16 million of undrawn letters of credit and $384 million of outstanding borrowings under our $1.25 billion credit facility. In addition we had $21 million outstanding under our money market lines of credit. Our available borrowing capacity under our credit arrangements was approximately $949 million.

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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.

At September 30, 2009, we had positive working capital of $137 million compared to $121 million at December 31, 2008. The increase in our working capital balance at September 30, 2009 is primarily related to an increase in our cash balance of $72 million and the decrease in our accounts payable and accrued liabilities of $175 million due to lower capital spending in 2009. The increase was partially offset by the $185 million decrease in derivative assets and their related deferred taxes resulting from a combination of contracts that settled during the period and lower commodity prices.

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 flows from operations was $1.2 billion for the nine months ended September 30, 2009, an increase of 96% compared to net cash flows from operations of $622 million for the same period in 2008. This increase is primarily due to the $558 million payment in 2008 to reset our 2009 and 2010 crude oil hedging contracts.

Cash Flows from Investing Activities. Net cash used in investing activities for the nine months ended September 30, 2009 was $1.0 billion compared to $1.7 billion for the same period in 2008.

During the nine months ended September 30, 2009, we:

- spent $1.1 billion primarily for additions to oil and gas properties; and
- redeemed investments of $18 million.

During the nine months ended September 30, 2008, we:

- spent $1.8 billion primarily for additions to oil and gas properties (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 $946 million for the first nine months of 2009 decreased 46% from our capital expenditures of $1.8 billion during the same period of 2008. These amounts exclude recorded asset retirement costs of $8 million and $3 million in 2009 and 2008, respectively. Of the $946 million spent during the first nine months of 2009, we invested $685 million in domestic exploitation and development, $133 million in domestic exploration (exclusive of exploitation and leasehold activity), $34 million in domestic leasehold activity and $94 million internationally. Of the $1.8 billion spent during the first nine months of 2008, we invested $963 million in domestic exploitation and development, $275 million in domestic exploration (exclusive of exploitation and leasehold activity), $346 million in domestic leasehold activity (includes the acquisition of properties in South Texas) and $171 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.

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Cash Flows from Financing Activities. Net cash flows used in financing activities for the first nine months of 2009 were $102 million compared to $895 million of net cash flows provided by financing activities for the same period in 2008.

During the first nine months of 2009, we:

- borrowed $813 million and repaid $920 million under our credit arrangements; and
- received proceeds of $6 million from the issuance of shares of our common stock upon the exercise of stock options.

During the first nine months of 2008, we:

- borrowed $1.8 billion and repaid $1.5 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 September 30, 2009.

	Total	Less than 1 Year	2-3 Years (In millions)	4-5 Years	More than 5 Years
Debt:					
Revolving credit facility	$454	$—	$454	$—	$—
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	2,104	—	629	325	1,150
Other obligations:					
Interest payments(1)	781	119	217	201	244
Net derivative (assets) liabilities	(400)	(377)	(23)	—	—
Asset retirement obligations	83	6	7	10	60
Operating leases	133	63	24	18	28
Deferred acquisition payments	2	2	—	—	—
Firm transportation	240	30	60	58	92
Oil and gas activities(2)	514	—	—	—	—
Total other (assets) obligations	1,353	(157)	285	287	424
Total contractual (assets) obligations	$3,457	$(157)	$914	$612	$1,574

(1) Interest associated with our revolving credit facility was calculated using a weighted average interest rate of approximately 1.1% at September 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 September 30, 2009, these work-related commitments totaled $514 million and were comprised of $380 million domestically and $134 million internationally. 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 September 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 82% of our future hedged production, the largest of which was J Aron & Company and accounts for 26% 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 $0.25-$0.50 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 75-85% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 17 Bcf of our natural gas production from October 2009 through December 2012 to lock in the differential at a weighted average of $0.98 per MMBtu less than the Henry Hub Index. In total, this hedge and the 8,000 MMBtus per day we have sold on a fixed physical basis for the same period results in an average basis hedge of $0.94 per MMBtu. In the Mid-Continent, we hedged basis associated with approximately 14 Bcf of our anticipated Stiles/Britt Ranch natural gas production from October 2009 through August 2011. In total, this hedge and the 30,000 MMBtus per day we have sold on a fixed physical basis for the same period results in an average basis hedge of $0.52 per MMBtu. We have also hedged basis associated with approximately 23 Bcf of our natural gas production from this area for the period September 2011 through December 2012 at an average of $0.55 per MMBtu.

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 90-95% of WTI. Oil sales from our operations in China typically sell at $6-$8 per barrel less than the WTI price.

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New Accounting Standards

In September 2006, the Financial Accounting Standards Board (FASB) defined fair value, established criteria to be considered when measuring fair value and expanded disclosures about fair value measurements. The guidance 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 for all recurring measures of financial assets and liabilities on January 1, 2008. In February 2008, the FASB issued additional authoritative guidance, which granted a one-year deferral of the effective date 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 the provisions to non-financial assets and liabilities.   The adoption did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued guidance requiring enhanced disclosures about our derivative and hedging activities that is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements beginning January 1, 2009. Please see Note 7, “Derivative Financial Instruments – Additional Disclosures about Derivative Instruments and Hedging Activities.” The adoption did not have an impact on our financial position or results of operations.

In April 2009, the FASB issued additional guidance regarding fair value measurements and impairments of securities which makes fair value measurements more consistent with fair value principles, enhances consistency in financial reporting by increasing the frequency of fair value disclosures, and provides greater clarity and consistency in accounting for and presenting impairment losses on securities. The additional guidance is 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 for the period ending March 31, 2009. The adoption did not have a material impact on our financial position or results of operations.

In May 2009, the FASB established 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 guidance is based on the same principles as those that previously existed. This guidance, 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. Our adoption of these provisions beginning with the period ending June 30, 2009 did not have an impact on our financial position or results of operations.

In September 2009, the FASB issued its proposed updates to oil and gas accounting rules to align the oil and gas reserve estimation and disclosure requirements of Extractive Industries—Oil and Gas (Topic 932) with the requirements in the Securities and Exchange Commission’s final rule, Modernization of the Oil and Gas Reporting Requirements, which was issued on December 31, 2008 and is effective for the year ended December 31, 2009. The public comment period for the FASB’s proposed updates ended October 15, 2009; however, no final guidance has been issued by the FASB. We are evaluating the potential impact of any updates to the oil and gas accounting rules and will comply with any new accounting and disclosure requirements once they become effective.

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 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 our quarterly report on Form 10-Q for the quarter ended June 30, 2009.

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 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 September 30, 2009, our debt included:

	Fixed Rate Debt (In millions)	Variable Rate Debt
Bank revolving credit facility	$	$ 454
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	$ 504

(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 24% 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 $0.5 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 September 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 September 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 third 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

There have been no material changes with respect to our risk factors previously reported in our annual report on Form 10-K for the year ended December 31, 2008 and our quarterly report on Form 10-Q for the quarter ended June 30, 2009.

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 September 30, 2009.

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate) Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs

July 1 – July 31, 2009	1,042	$ 33.34	—	—
August 1 – August 31, 2009	1,374	39.05	—	—
September 1 – September 30, 2009	5,138	41.96	—	—
Total	7,554	$ 40.24	—	—

(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 6. Exhibits

Exhibit Number	Description
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

* Filed or furnished herewith.

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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: October 23, 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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