NEWFIELD EXPLORATION CO /DE/
Form 10-Q
July 23, 2010

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

(Mark One)

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

For the Quarterly Period Ended June 30, 2010

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 July 20, 2010, there were 133,606,000 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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NEWFIELD EXPLORATION COMPANY

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

	June 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 122	$ 78
Accounts receivable	328	339
Inventories	82	84
Derivative assets	278	269
Other current assets	94	123
Total current assets	904	893
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,588 and $1,223 were excluded from amortization at June 30, 2010 and December 31, 2009, respectively)	11,413	10,406
Less accumulated depreciation, depletion and amortization	(5,464)	(5,159)
Total property and equipment, net	5,949	5,247
Derivative assets	61	19
Long-term investments	47	55
Deferred taxes	27	26
Other assets	20	14
Total assets	$ 7,008	$ 6,254
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 102	$ 83
Accrued liabilities	644	640
Advances from joint owners	70	51
Asset retirement obligation	14	10
Derivative liabilities	—	2
Deferred taxes	91	87
Total current liabilities	921	873
Other liabilities	99	55
Derivative liabilities	4	5
Long-term debt	2,169	2,037
Asset retirement obligation	85	82
Deferred taxes	602	434
Total long-term liabilities	2,959	2,613
Commitment and contingencies (Note 12)	—	—
Stockholders' equity:		

Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)		—		—
Common stock ($0.01 par value, 200,000,000 shares authorized at June 30, 2010 and December 31, 2009;				
135,245,980 and 134,493,670 shares issued at June 30, 2010 and December 31, 2009 respectively)		1		1
Additional paid-in capital		1,418		1,389
Treasury stock (at cost; 1,638,890 and 1,488,968 shares at June 30, 2010 and December 31, 2009, respectively)		(40)		(33)
Accumulated other comprehensive income (loss):				
Unrealized loss on investments		(13)		(11)
Retained earnings		1,762		1,422
Total stockholders' equity		3,128		2,768
Total liabilities and stockholders' equity	$	7,008	$	6,254

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

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Oil and gas revenues	$ 448	$ 287	$ 906	$ 549
Operating expenses:				
Lease operating	84	57	151	128
Production and other taxes	31	15	56	24
Depreciation, depletion and amortization	160	137	307	296
General and administrative	41	34	77	66
Ceiling test writedown	—	—	—	1,344
Other	2	5	10	7
Total operating expenses	318	248	601	1,865
Income (loss) from operations	130	39	305	(1,316)
Other income (expenses):				
Interest expense	(39)	(32)	(77)	(64)
Capitalized interest	16	12	28	26
Commodity derivative income (expense)	46	(81)	283	197
Other	(1)	2	1	5
Total other income (expense)	22	(99)	235	164
Income (loss) before income taxes	152	(60)	540	(1,152)
Income tax provision (benefit):				
Current	14	(4)	27	1
Deferred	42	(17)	173	(420)
Total income tax provision (benefit)	56	(21)	200	(419)
Net income (loss)	$ 96	$ (39)	$ 340	$ (733)
Income (loss) per share:				
Basic	$ 0.73	$ (0.30)	$ 2.59	$ (5.66)
Diluted	$ 0.72	$ (0.30)	$ 2.55	$ (5.66)
Weighted average number of shares outstanding for basic income (loss) per share	132	130	131	129
	134	130	133	129

Weighted average number of shares outstanding for diluted income (loss) per share

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)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash flows from operating activities:		
Net income (loss)	$340	$(733)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	307	296
Deferred tax provision (benefit)	173	(420)
Stock-based compensation	12	15
Ceiling test writedown	—	1,344
Commodity derivative income	(283)	(197)
Cash receipts on derivative settlements	227	459
Changes in operating assets and liabilities:		
Decrease in accounts receivable	11	85
(Increase) decrease in inventories	6	(30)
(Increase) decrease in other current assets	29	(41)
Decrease in other assets	1	14
Increase (decrease) in accounts payable and accrued liabilities	40	(78)
Increase (decrease) in advances from joint owners	19	(19)
Increase in other liabilities	6	17
Net cash provided by operating activities	888	712
Cash flows from investing activities:		
Additions to oil and gas properties	(767)	(778)
Acquisitions of oil and gas properties	(219)	(9)
Proceeds from sales of oil and gas properties	14	—
Additions to furniture, fixtures and equipment	(7)	(3)
Redemption of investments	5	14
Net cash used in investing activities	(974)	(776)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	322	732
Repayments of borrowings under credit arrangements	(707)	(654)
Net proceeds from issuance of senior subordinated notes	686	—
Repayment of senior notes	(175)	—
Proceeds from issuances of common stock	17	1
Purchases of treasury stock, net	(13)	(1)
Net cash provided by financing activities	130	78
Increase in cash and cash equivalents	44	14
Cash and cash equivalents, beginning of period	78	24

Cash and cash equivalents, end of period	$122	$38

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

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive Income (Loss)	Total Stockholders'
	Shares	Amount	Shares	Amount	Capital	Earnings		Equity
Balance, December 31, 2009	134.5	$ 1	(1.5)	$ (33)	$ 1,389	$ 1,422	$ (11)	$ 2,768
Issuances of common and restricted stock	0.7	—			11			11
Treasury stock, at cost			(0.1)	(7)				(7)
Stock-based compensation					18			18
Comprehensive income (loss):								
Net income						340		340
Unrealized loss on investments							(2)	(2)
Total comprehensive income								338
Balance, June 30, 2010	135.2	$ 1	(1.6)	$ (40)	$ 1,418	$ 1,762	$ (13)	$ 3,128

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

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

Our 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, 2009.

Dependence on Oil and 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 gas. Historically, the energy markets have been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil or 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 and fair value of our derivative positions.

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 regularly assess our investments for impairment and consider any impairment to be other than temporary if we intend to sell the security, it is more likely than not that we will be required to sell the security, or we do not expect to recover our cost of the security. We realized interest income and gains on our investment securities for the three months ended June 30, 2010 and 2009 of $0.4 million and $0.5 million, respectively, and for the six months ended June 30, 2010 and 2009 of $1 million and $2 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 FPSO’s and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 505,000 barrels and 289,000 barrels of crude oil valued at cost of $22 million and $11 million at June 30, 2010 and December 31, 2009, 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 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. Beginning January 1, 2010, 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 the newly effective oil and gas reserve estimation requirements (See “New Accounting Requirements” in this Note) which require use of the unweighted average first-day-of-the-month commodity prices for the prior twelve months, adjusted for market differentials 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.

During the first and second quarters of 2009, the present value (10% per annum discount rate) of estimated future net revenues from proved reserves was calculated using the end of period quoted market prices for oil and gas.

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 gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At June 30, 2010, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior twelve months of $4.10 per MMBtu for natural gas and $75.78 per barrel for oil, adjusted for market differentials. Using these prices, 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 at June 30, 2010.

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 period-end 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 and, as a result, we recorded a charge of $1.3 billion ($854 million, after-tax).

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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 in depreciation, depletion and amortization expense on our consolidated statement of income.

The change in our ARO for the six months ended June 30, 2010 is set forth below (in millions):

Balance as of January 1, 2010	$	92
Accretion expense		4
Additions		5
Settlements		(2)
Balance at June 30, 2010	$	99
Less: Current portion of ARO at June 30, 2010		(14)
Total long-term ARO at June 30, 2010	$	85

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 in 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.

As of June 30, 2010, we did not have any liability for uncertain tax positions. The tax years 2006-2009 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 (IRS) commenced a limited scope audit of our U.S. income tax return for the 2005 tax year. In 2010, the IRS issued a “No Change” letter for the 2005 tax year and closed the audit.

Derivative Financial Instruments

We account for our derivative activities by applying authoritative accounting and reporting guidance which requires that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured 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. 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. Previously, we also utilized derivatives to manage our exposure to variable interest rates. See Note 5, “Derivative Financial Instruments—Interest Rate Swap.”

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. See Note 5 “Derivative Financial Instruments,” for a more detailed discussion of our derivative activities.

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

New Accounting Requirements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03), which aligns the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the Securities and Exchange Commission's final rule, Modernization of the Oil and Gas Reporting Requirements (Final Rule), which was issued on December 31, 2008 and became effective for the year ended December 31, 2009. We adopted the Final Rule and ASU 2010-03 effective December 31, 2009, as a change in accounting principle that is inseparable from a change in accounting estimate. Such a change is accounted for prospectively under the authoritative accounting guidance. Comparative disclosures applying the new rules for periods before the adoption of ASU 2010-03 and the Final Rule are not required.

In January 2010, the FASB issued additional disclosure requirements related to fair value measurements. The guidance requires disclosure of transfers of assets and liabilities between Level 1 and Level 2 in the fair value measurement hierarchy, including the reasons for the transfers and disclosure of major purchases, sales, issuances, and settlements on a gross basis in the reconciliation of the assets and liabilities measured under Level 3 of the fair value measurement hierarchy. The guidance is effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures which are effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ending March 31, 2010, except for the Level 3 reconciliation disclosures, which we will adopt for the quarter ending March 31, 2011. Adopting the disclosure requirements did not have an impact on our financial position or results of operations. We do not expect adoption of the Level 3 reconciliation disclosures in 2011 to have an impact on our financial position or results of operations.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock (other than unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted 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 June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In millions, except per share data)			
Income (numerator):				
Net income (loss) — basic and diluted	$ 96	$ (39)	$ 340	$ (733)
Weighted average shares (denominator):				
Weighted average shares — basic	132	130	131	129
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period (1)	2	—	2	—
Weighted average shares — diluted	134	130	133	129
Income (loss) per share:				
Basic	$ 0.73	$ (0.30)	$ 2.59	$ (5.66)
Diluted	$ 0.72	$ (0.30)	$ 2.55	$ (5.66)

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

3. Comprehensive Income (Loss):

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In millions)			
Net income (loss)	$ 96	$ (39)	$ 340	$ (733)
Unrealized gain (loss) on investments, net of tax of $1 for the three and six months ended June 30, 2010 and net of tax of ($1) for the three months ended June 30, 2009	(3)	2	(2)	—
Total comprehensive income (loss)	$ 93	$ (37)	$ 338	$ (733)

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4. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

	June 30, 2010	December 31, 2009
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 9,726	$ 9,090
Not subject to amortization	1,588	1,223
Gross oil and gas properties	11,314	10,313
Accumulated depreciation, depletion and amortization	(5,408)	(5,108)
Net oil and gas properties	5,906	5,205
Other property and equipment	99	93
Accumulated depreciation and amortization	(56)	(51)
Net other property and equipment	43	42
Total property and equipment, net	$ 5,949	$ 5,247

The following is a summary of our oil and gas properties not subject to amortization as of June 30, 2010. We believe that our evaluation activities related to substantially all of our properties not subject to amortization will be completed within four years except the Monument Butte field. Because of its size, evaluation of the field in its entirety will take significantly longer than four years.

	Costs Incurred In				
	2010	2009	2008	2007 and prior	Total
			(In millions)		
Acquisition costs	$ 204	$ 153	$ 171	$372	$ 900
Exploration costs	198	87	57	22	364
Development costs	67	27	34	25	153
Fee mineral interests	2	—	—	23	25
Capitalized interest	28	51	60	7	146
Total oil and gas properties not subject to amortization	$ 499	$ 318	$ 322	$449	$ 1,588

Maverick Basin Asset Acquisition

On February 11, 2010, we acquired certain of TXCO Resources Inc.'s assets in the Maverick Basin of southwest Texas for approximately $215 million. In the acquisition, we obtained an interest in approximately 300,000 net acres, primarily in the Pearsall and Eagle Ford shale plays, as well as production of 1,500 barrels of oil equivalent per day. Our consolidated financial statements include the cash flows and results of operations for these assets subsequent to February 11, 2010.

5. 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.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions "Derivative assets" and "Derivative liabilities." 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 8, "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.

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

At June 30, 2010, 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 (Liability)
		Swaps	Additional Put		Floors		Ceilings			
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average		(In millions)
July 2010 – September 2010										
Price swap contracts	35,200	$6.41	—	—	—	—	—	—		$ 60
October 2010 – December 2010										
Price swap contracts	28,320	6.49	—	—	—	—	—	—		43
January 2011 – December 2011										
Price swap contracts	85,740	6.26	—	—	—	—	—	—		82
3-Way collar contracts	42,590	—	$4.50	$4.50	$6.00	$6.00	$7.10 - 8.03	$7.84		26
January 2012 – December 2012										
Price swap contracts	18,300	5.42	—	—	—	—	—	—		(3)
3-Way collar contracts	40,870	—	4.50	4.50	5.75-6.00	5.82	6.20 - 7.55	6.80		4
January 2013 – October 2013										
3-Way collar contracts	21,280	—	4.50	4.50	5.75-6.00	5.82	6.60 - 7.55	6.88		—

	$ 212

Oil

Period and Type of Contract	Volume in MBbls	Swaps (Weighted Average)	Additional Put Range	Additional Put Weighted Average	Collars Floors Range	Collars Floors Weighted Average	Collars Ceilings Range	Collars Ceilings Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
		NYMEX Contract Price Per Bbl							
July 2010 – September 2010									
Price swap contracts	550	$87.74	—	—	—	—	—	—	$ 6
Collar contracts	828	—	—	—	$125.50–130.50	$127.97	$170.00	$170.00	43
3-Way collar contracts	368	—	$50.00-60.00	$55.00	60.00-75.00	67.50	100.00-112.10	106.28	1
October 2010 – December 2010									
Price swap contracts	550	87.74	—	—	—	—	—	—	6
Collar contracts	828	—	—	—	125.50–130.50	127.97	170.00	170.00	42
3-Way collar contracts	368	—	50.00-60.00	55.00	60.00-75.00	67.50	100.00-112.10	106.28	1
January 2011 – December 2011									
Price swap contracts	2,190	80.44	—	—	—	—	—	—	2
3-Way collar contracts	5,659	—	60.00-65.00	61.61	75.00-85.00	77.58	102.25-121.50	107.76	22
January 2012 – December									

2012									
Price swap contracts	2,196	82.27	—	—	—	—	—	—	2
3-Way collar contracts	4,392	—	60.00-65.00	61.25	75.00-85.00	77.50	111.00-115.00	112.16	9
									$ 134

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

Basis Contracts

At June 30, 2010, 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 MMMBtus	Weighted Average Differential	Volume in MMMBtus	Weighted Average Differential	Fair Value Asset (Liability) (In millions)
July 2010 – September 2010	1,380	$(0.99)	1,840	$(0.55)	$(1)
October 2010 – December 2010	1,380	(0.99)	1,840	(0.55)	(1)
January 2011 – December 2011	5,280	(0.95)	10,350	(0.55)	(4)
January 2012 – December 2012	4,920	(0.91)	18,300	(0.55)	(5)
					$(11)

Interest Rate Swap

We previously hedged $50 million principal amount of our $175 million 7 % Senior Notes due 2011 through an interest rate swap. The swap provided for us to pay variable and receive fixed payments. During the first quarter of 2010, we terminated the swap and received approximately $2 million in settlement of the swap.

Additional Disclosures about Derivative Instruments and Hedging Activities

At June 30, 2010, 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	$ 168
Oil contracts	Derivative assets – current	114
Basis contracts	Derivative assets – current	(4)
Natural gas contracts	Derivative assets – noncurrent	44
Oil contracts	Derivative assets – noncurrent	20
Basis contracts	Derivative assets – noncurrent	(3)
Basis contracts	Derivative liabilities – noncurrent	(4)
Total derivatives not designated as hedging instruments, net		$ 335

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

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

Type of Contract	Location of Gain/(Loss) Recognized in Income	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
		(In millions)			
Derivatives not designated as hedging instruments:					
Realized gain on natural gas contracts	Commodity derivative income (expense)	$ 81	$ 152	$ 144	$ 241
Realized gain on oil contracts	Commodity derivative income (expense)	37	89	71	204
Realized gain (loss) on basis contracts	Commodity derivative income (expense)	(1)	—	(3)	1
Total realized gain		117	241	212	446
Unrealized gain (loss) on natural gas contracts	Commodity derivative income (expense)	(110)	(132)	80	53
Unrealized gain (loss) on oil contracts	Commodity derivative income (expense)	33	(185)	(12)	(283)
Unrealized gain (loss) on basis contracts	Commodity derivative income (expense)	6	(5)	3	(19)
Total unrealized gain (loss)		(71)	(322)	71	(249)
Total gain (loss) on derivatives not designated as hedging instruments		46	(81)	283	197
Derivative designated as a fair value hedge:					
Interest rate swap	Interest expense	—	1	—	1
Total		$ 46	$ (80)	$ 283	$ 198

The total realized gain on commodity derivatives differs from the cash receipts on derivative settlements due to the recognition of option premiums associated with derivatives settled during the period.

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate derivative instruments with that counterparty. At June 30, 2010, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to 86% of our future hedged production, the largest of which was J Aron & Company and accounted for 25% of our future hedged production.

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

6. Accounts Receivable:

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

	June 30, 2010	December 31, 2009
	(In millions)	
Revenue	$195	$214
Joint interest	114	114
Other	20	17
Reserve for doubtful accounts	(1)	(6)
Total accounts receivable	$328	$339

7. Accrued Liabilities:

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

	June 30, 2010	December 31, 2009
	(In millions)	
Revenue payable	$79	$55
Accrued capital costs	308	289
Accrued lease operating expenses	44	47
Employee incentive expense	43	61
Accrued interest on debt	41	25
Taxes payable	79	101
Other	50	62
Total accrued liabilities	$644	$640

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8. Fair Value Measurements:

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 authoritative guidance requires disclosure of the framework for measuring fair value 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, certain 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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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Fair Value of Investments and Derivative Instruments

The following tables summarize the valuation of our investments and financial instrument assets (liabilities) by pricing levels:

	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
	(In millions)			
As of December 31, 2009:				
Money market fund investments	$ 15	$ —	$ —	$ 15
Investments available-for-sale:				
Equity securities	7	—	—	7
Auction rate securities	—	—	40	40
Oil and gas derivative swap contracts	—	119	(14)	105
Oil and gas derivative option contracts	—	—	173	173
Interest rate swap	—	3	—	3
Total	$ 22	$ 122	$ 199	$ 343
As of June 30, 2010:				
Money market fund investments	$ 27	$ —	$ —	$ 27
Investments available-for-sale:				
Equity securities	7	—	—	7
Auction rate securities	—	—	33	33
Oil and gas derivative swap contracts	—	198	(11)	187
Oil and gas derivative option contracts	—	—	148	148
Total	$ 34	$ 198	$ 170	$ 402

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 June 30, 2010, we continued to hold $33 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 $17 million ($11 million net of tax), recorded under the caption “Accumulated other comprehensive income (loss)” on our consolidated balance sheet. The debt instruments underlying these investments are mostly 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.

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

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

	Investments	Derivatives (In millions)	Total
Balance at January 1, 2009	$ 59	$ 542	$ 601
Total realized or unrealized gains (losses):			
Included in earnings		(33)	(33)
Purchases, issuances and settlements	(14)	(176)	(190)
Transfers in and out of Level 3	—	—	—
Balance at June 30, 2009	$ 45	$ 333	$ 378
Change in unrealized gains (losses) relating to investments and derivatives still held at June 30, 2009	$ —	$ (65)	$ (65)
Balance at January 1, 2010	$ 40	$ 159	$ 199
Total realized or unrealized gains (losses):			
Included in earnings	—	43	43
Included in other comprehensive income (loss)	(2)	—	(2)
Purchases, issuances and settlements	(5)	(65)	(70)
Transfers in and out of Level 3	—	—	—
Balance at June 30, 2010	$ 33	$ 137	$ 170
Change in unrealized gains (losses) relating to investments and derivatives still held at June 30, 2010	$ (2)	$ 53	$ 51

Fair Value of Debt

The estimated fair value of our notes, based on quoted market prices on June 30, 2010, was as follows (in millions):

6 % Senior Subordinated Notes due 2014	$328
6 % Senior Subordinated Notes due 2016	549
7 % Senior Subordinated Notes due 2018	599
6 % Senior Subordinated Notes due 2020	697

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

9. Debt:

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

	June 30, 2010	December 31, 2009
	(In millions)	
Senior unsecured debt:		
Revolving credit facility:		
LIBOR based loans	$—	$384
7 % Senior Notes due 2011	—	175
Fair value of interest rate swap(1)	—	3
Total senior unsecured notes	—	178
Total senior unsecured debt	—	562
6 % Senior Subordinated Notes due 2014	325	325
6 % Senior Subordinated Notes due 2016	550	550
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	694	—
Total debt	$2,169	$2,037

(1) We previously hedged $50 million principal amount of our $175 million 7 % Senior Notes due 2011 through an interest rate swap. The swap provided for us to pay variable and receive fixed payments. During the first quarter of 2010, we terminated the swap and received approximately $2 million in settlement of the swap.

Credit Arrangements

We have a revolving credit facility which provides for loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank, as agent, and matures June 2012. However, the amount that we can borrow under the facility could be limited by changing expectations of future oil and gas prices because the maximum amount that we can borrow under the facility is determined by our lenders annually each May (and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures) using a process that takes into account the value of our estimated reserves and hedge position and the lenders' commodity price assumptions. In the future, total 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. We do not believe we could access such additional capacity in the current credit market. As of June 30, 2010, the largest commitment was 16% of total commitments.

Loans under the credit facility bear interest, at our option, equal to (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate substantially equal to the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (87.5 basis points per annum at June 30, 2010).

We pay commitment fees on available but undrawn amounts based on a grid of our debt rating (0.175% per annum at June 30, 2010). We incurred fees under this arrangement of approximately $0.5 million and $1 million for the three and six months ended June 30, 2010, respectively, which are recorded in interest expense on our consolidated statement of income. For the three and six months ended June 30, 2009, we incurred commitment fees of approximately $0.3 million and $0.7 million, respectively.

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, if our debt rating is below investment grade, we must maintain a ratio of the calculated net present value of our oil and gas reserves to total debt of at least 1.75 to 1.00. For purposes of this ratio, total debt includes only 50% of the principal amount of our senior subordinated notes. At June 30, 2010 we were in compliance with all of our debt covenants.

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

As of June 30, 2010, we had no letters of credit outstanding under our credit facility. Letters of credit are subject to an issuance fee of 12.5 basis points and annual fees based on a grid of our debt rating (87.5 basis points at June 30, 2010).

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $105 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

Our credit facility 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.

Senior and Senior Subordinated Notes

On January 25, 2010, we sold $700 million of 6 % Senior Subordinated Notes due 2020 and received net proceeds of $686 million (net of discount and offering costs). These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility and $215 million to fund the acquisition of assets from TXCO Resources Inc.

On February 19, 2010, we accepted for purchase and payment approximately $143 million of our $175 million aggregate principal amount of 7 % Senior Notes due 2011, representing approximately 82% of the outstanding principal. The tender included the payment of an early redemption premium of $10 million. This premium was recorded under the caption “Operating expenses – Other” on our consolidated statement of income.

On May 24, 2010, we accepted for purchase and payment the remaining $32 million of our $175 million aggregate principal amount 7 % Senior Notes due 2011. The tender included the payment of an early redemption premium of $2 million. This premium was recorded under the caption “Operating expenses – Other” on our consolidated statement of income.

We funded the tender offer with a portion of the proceeds from our January 25, 2010 Senior Subordinated Notes issuance.

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10. Income Taxes:

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In millions)			
Amount computed using the statutory rate	$ 53	$ (21)	$ 189	$ (404)
Increase (decrease) in taxes resulting from:				
State and local income taxes, net of federal effect	2	1	8	(17)
Net effect of different tax rates in non-U.S. jurisdictions	1	1	3	1
Valuation allowance	—	(3)	—	—
Other	—	1	—	1
Total income tax provision (benefit)	$ 56	$ (21)	$ 200	$ (419)

As of June 30, 2010, we had net operating loss (NOL) carryforwards for international income tax purposes of approximately $17 million. We currently estimate that we will not be able to utilize our international NOLs because we do not have sufficient estimated future taxable income in the appropriate jurisdictions. Therefore, valuation allowances have been established for these items. Estimates of future taxable income can be significantly affected by changes in oil and gas prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

11. Stock-Based Compensation:

We make stock-based compensation awards to employees through the Newfield Exploration Company 2009 Omnibus Stock Plan (the 2009 Omnibus Stock Plan) and to non-employee directors through the Newfield Exploration Company 2009 Non-Employee Director Restricted Stock Plan. The fair value of grants under these plans are determined utilizing the Black-Scholes option pricing model for stock options and a lattice-based model for our performance and market-based restricted stock and restricted stock units.

As of the indicated dates, our stock-based compensation consisted of the following:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In millions)			
Total stock-based compensation	$ 9	$ 11	$ 18	$ 23
Capitalized in oil and gas properties	(3)	(4)	(6)	(8)
Net stock-based compensation expense	$ 6	$ 7	$ 12	$ 15

As of June 30, 2010, we had approximately $62 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
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Stock Options. The following table provides information about stock option activity for the six months ended June 30, 2010:

	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, 2009	2.9	$ 29.82		4.7	$ 56
Granted	—	—	$ —		
Exercised	(0.7)	23.17			22
Forfeited	—	—			
Outstanding at June 30, 2010	2.2	$ 31.89		4.7	$ 38
Exercisable at June 30, 2010	1.9	$ 29.54		4.2	$ 38

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

On June 30, 2010, the last reported sales price of our common stock on the New York Stock Exchange was $48.86 per share.

Restricted Stock. The following table provides information about restricted stock and restricted stock unit activity for the six months ended June 30, 2010:

	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, 2009	2,424	782	3,206	$ 31.60
Granted	429	140	569	50.53
Forfeited	(104)	(85)	(189)	30.25
Vested	(535)	(521)	(1,056)	31.34
Non-vested shares outstanding at June 30, 2010	2,214	316	2,530	$ 36.05

Employee Stock Purchase Plan. During the first six months of 2010, options to purchase 37,746 shares of our common stock were issued under our 2001 employee stock purchase plan. The weighted average fair value of each option was $13.08 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 0.20%, an expected life of six months and weighted average volatility of 43%. At June 30, 2010, this plan was terminated.

At our May 7, 2010 annual meeting, our stockholders approved the Newfield Exploration Company 2010 Employee Stock Purchase Plan. This plan is effective July 1, 2010 and has 1,000,000 shares of our common stock available for issuance.

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

12. 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.

13. Segment Information:

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

The following tables provide the geographic operating segment information as of and for the three and six months ended June 30, 2010 and 2009. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

Three Months Ended June 30, 2010:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Oil and gas revenues	$ 340	$ 94	$ 14	$ —	$ 448
Operating expenses:					
Lease operating	71	12	1	—	84
Production and other taxes	15	14	2	—	31
Depreciation, depletion and amortization	128	28	4	—	160
General and administrative	39	2	—	—	41
Other	2	—	—	—	2
Allocated income taxes	32	15	2	—	
Net income from oil and gas properties	$ 53	$ 23	$ 5	$ —	
Total operating expenses					318
Income from operations					130
Interest expense, net of interest income,					
capitalized interest and other					(24)
Commodity derivative income					46
Income before income tax					$ 152
Total long-lived assets	$ 5,332	$ 403	$ 171	$ —	$ 5,906

Additions to long-lived assets	$ 386	$ 39	$ 16	$ —	$ 441

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Three Months Ended June 30, 2009:

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

Six Months Ended June 30, 2010:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Oil and gas revenues	$ 698	$ 179	$ 29	$ —	$ 906
Operating expenses:					
Lease operating	127	22	2	—	151
Production and other taxes	30	21	5	—	56
Depreciation, depletion and amortization	243	53	8	3	307
General and administrative	73	3	1	—	77
Other	10	—	—	—	10
Allocated income taxes	79	30	4	—	
Net income (loss) from oil and gas properties	$ 136	$ 50	$ 9	$ (3)	
Total operating expenses					601

Income from operations										305
Interest expense, net of interest income,										
capitalized interest and other										(48)
Commodity derivative income										283
Income before income tax									$	540
Total long-lived assets	$	5,332	$	403	$	171	$	—	$	5,906
Additions to long-lived assets	$	912	$	80	$	24	$	—	$	1,016

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Six Months Ended June 30, 2009:

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

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

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

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

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

Any extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. Please see the discussion under "Lower oil and gas prices and other factors have resulted in ceiling test writedowns in the past and may in the future result in additional ceiling test writedowns or other impairments" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2009 and "— Liquidity and Capital Resources" below.

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

Reserve Replacement. To maintain and grow our production and cash flow, we must continue to develop existing reserves and locate or acquire new oil and gas reserves to replace those reserves being produced. 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.

Accounting for Hedging Activities. We do not designate price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of June 30, 2010, we had net derivative assets of $335 million, of which 41% was measured based upon our valuation model (i.e. Black-Scholes) and, as such, is classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. Please see Note 5, “Derivative Financial Instruments,” and Note 8, “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, 2009 and in Item 1A of this report for a discussion of a number of other factors that affect our business, financial condition and results of operations. This report should be read together with those discussions.

Results of Operations

Revenues. All of our revenues are derived from the sale of our oil and gas production and do not include the effects of the settlements of our hedges. Please see Note 5, “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 $448 million for the second quarter of 2010 were 56% higher than the comparable period of 2009. Revenues of $906 million for the first six months of 2010 were 65% higher than the comparable period of 2009. The revenue increase for both periods is due to higher average realized oil and gas prices, combined with higher oil and gas production.

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	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Percentage Increase (Decrease)	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Percentage Increase (Decrease)
Production: (1)						
Domestic:						
Natural gas (Bcf)	50.2	45.2	11 %	97.0	90.1	8 %
Oil and condensate (MBbls)	2,114	1,869	13 %	3,873	3,637	7 %
Total (Bcfe)	62.9	56.4	11 %	120.3	111.9	8 %
International:						
Natural gas (Bcf)	—	—	—	—	—	—
Oil and condensate (MBbls)	1,491	1,365	9 %	2,893	2,566	13 %
Total (Bcfe)	8.9	8.2	9 %	17.3	15.4	13 %
Total:						
Natural gas (Bcf)	50.2	45.2	11 %	97.0	90.1	8 %
Oil and condensate (MBbls)	3,605	3,234	12 %	6,766	6,203	9 %
Total (Bcfe)	71.8	64.6	11 %	137.6	127.3	8 %
Average Realized Prices: (2)						
Domestic:						
Natural gas (per Mcf)	$ 3.88	$ 2.85	36 %	$ 4.44	$ 3.16	41 %
Oil and condensate (per Bbl)	67.47	49.24	37 %	68.29	40.98	67 %
Natural gas equivalent (per Mcfe)	5.39	3.92	37 %	5.81	3.88	50 %
International:						
Natural gas (per Mcf)	$ —	$ —	—	$ —	$ —	—
Oil and condensate (per Bbl)	72.90	47.29	55 %	71.74	44.19	63 %
Natural gas equivalent (per Mcfe)	12.15	7.86	55 %	11.96	7.36	63 %
Total:						
Natural gas (per Mcf)	$ 3.88	$ 2.85	36 %	$ 4.44	$ 3.16	41 %
Oil and condensate (per Bbl)	69.72	48.42	44 %	69.77	42.31	65 %
Natural gas equivalent (per Mcfe)	6.23	4.42	41 %	6.58	4.30	53 %

(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 $5.47 and $6.21 per Mcf for the three months ended June 30, 2010 and 2009, respectively, and $5.89 and $5.84 per Mcf for the six months ended June 30, 2010 and 2009, respectively. Our total oil and condensate average realized price would have been $79.94 and $76.09 per Bbl for the three months ended June 30, 2010 and 2009, respectively, and $80.18 and $75.29 per Bbl for the six months ended June 30, 2010 and 2009, respectively.

Domestic Production. Our three and six months ended June 30, 2010 domestic oil and gas production, stated on a natural gas equivalent basis, increased over the comparable periods of 2009 primarily due to increased production from continued development of our Gulf of Mexico deepwater discoveries, combined with increased production in our Mid-Continent division as a result of continued successful development drilling efforts, partially offset by a decline in our onshore Gulf Coast production.

International Production. Our three and six months ended June 30, 2010 international oil production, stated on a natural gas equivalent basis, increased over the comparable periods of 2009 primarily due to the timing of liftings from our oil production in Malaysia and China.

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Operating Expenses. We believe the most informative way to analyze changes in our operating expenses from period to period is on a unit-of-production, or per Mcfe, basis.

The following table presents information about our operating expenses for the three months ended June 30, 2010 and 2009.

	Unit-of-Production Three Months Ended June 30, 2010	2009	Percentage Increase (Decrease)	Total Amount Three Months Ended June 30, 2010	2009	Percentage Increase (Decrease)
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 1.14	$ 0.80	43 %	$ 71	$ 45	59 %
Production and other taxes	0.24	0.21	14 %	15	12	27 %
Depreciation, depletion and amortization	2.02	1.94	4 %	128	110	16 %
General and administrative	0.61	0.57	7 %	39	32	20 %
Other	0.03	0.09	(67)%	2	5	(68)%
Total operating expenses	4.04	3.61	12 %	255	204	25 %
International:						
Lease operating	$ 1.44	$ 1.44	—	$ 13	$ 12	10 %
Production and other taxes	1.80	0.34	429 %	16	3	481 %
Depreciation, depletion and amortization	3.61	3.33	8 %	32	27	18 %
General and administrative	0.28	0.22	27 %	2	2	38 %
Total operating expenses	7.13	5.33	34 %	63	44	46 %
Total:						
Lease operating	$ 1.18	$ 0.88	34 %	$ 84	$ 57	48 %
Production and other taxes	0.43	0.23	87 %	31	15	114 %
Depreciation, depletion and amortization	2.22	2.12	5 %	160	137	16 %
General and administrative	0.57	0.52	10 %	41	34	21 %
Other	0.02	0.08	(75)%	2	5	(68)%
Total operating expenses	4.42	3.83	15 %	318	248	28 %

Domestic Operations. Our domestic operating expenses for the three months ended June 30, 2010, stated on a Mcfe basis, increased 12% over the same period of 2009. The components of the significant period to period change are as follows:

- Lease operating expense (LOE) per Mcfe increased 43% due to increased transportation costs resulting from the commencement of firm transportation contracts during the third quarter of 2009 in our Mid-Continent division and increased workover activity in all divisions. This increase was partially offset by lower overall operating and service costs.

- Production and other taxes per Mcfe increased 14% primarily due to higher realized commodity prices during 2010.

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Our depreciation, depletion and amortization (DD&A) rate per Mcfe increased 4% primarily due to higher cost reserve additions subsequent to the second quarter of 2009. The 16% increase in total DD&A expense is a result of the 11% increase in our production volumes during the second quarter of 2010 compared to the same period of 2009.

- General and administrative (G&A) expense per Mcfe increased 7% primarily due to increased employee-related expenses associated with our growing domestic workforce. During the second quarter of 2010, we capitalized $11 million of direct internal costs as compared to $15 million in the second quarter of 2009.

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International Operations. Our international operating expenses for the three months ended June 30, 2010, stated on a Mcfe basis, increased 34% over the same period of 2009. The components of the significant period to period change are as follows:

- Production and other taxes increased significantly due to substantially higher realized oil prices during 2010.
- The DD&A rate per Mcfe increased 8% primarily due to unsuccessful exploratory drilling efforts in Malaysia.

The following table presents information about our operating expenses for the six months ended June 30, 2010 and 2009.

	Unit-of-Production Six Months Ended June 30, 2010	Unit-of-Production Six Months Ended June 30, 2009	Percentage Increase (Decrease)	Total Amount Six Months Ended June 30, 2010	Total Amount Six Months Ended June 30, 2009	Percentage Increase (Decrease)
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$ 1.06	$ 0.93	14 %	$ 127	$ 104	23 %
Production and other taxes	0.25	0.17	47 %	30	18	65 %
Depreciation, depletion and amortization	2.01	2.18	(8)%	243	244	(1)%
General and administrative	0.62	0.57	9 %	73	64	15 %
Ceiling test writedown	—	12.02	(100)%	—	1,344	(100)%
Other	0.08	0.06	33 %	10	7	47 %
Total operating expenses	4.02	15.93	(75)%	483	1,781	(73)%
International:						
Lease operating	$ 1.39	$ 1.57	(11)%	$ 24	$ 24	—
Production and other taxes	1.46	0.34	329 %	26	6	387 %
Depreciation, depletion and amortization	3.71	3.39	9 %	64	52	23 %
General and administrative	0.20	0.13	54 %	4	2	65 %
Total operating expenses	6.76	5.43	24 %	118	84	40 %
Total:						
Lease operating	$ 1.10	$ 1.00	10 %	$ 151	$ 128	19 %
Production and other taxes	0.41	0.19	116 %	56	24	136 %
Depreciation, depletion and amortization	2.23	2.32	(4)%	307	296	4 %
General and administrative	0.56	0.52	8 %	77	66	17 %
Ceiling test writedown	—	10.56	(100)%	—	1,344	(100)%
Other	0.07	0.05	40 %	10	7	47 %
Total operating expenses	4.37	14.64	(70)%	601	1,865	(68)%

Domestic Operations. Our domestic operating expenses for the six months ended June 30, 2010, stated on a Mcfe basis, decreased 75% over the same period of 2009 primarily due to the full cost ceiling test writedown recorded at March 31, 2009. The components of the significant period to period change are as follows:

- LOE per Mcfe increased 14% primarily due to increased transportation costs resulting from the commencement of firm transportation contracts during the third quarter of 2009 in our Mid-Continent division and increased workover activity in all divisions. This increase was partially offset by lower overall operating and service costs.

- Production and other taxes per Mcfe increased 47% due to significantly higher realized commodity prices during 2010.

- At March 31, 2009, we recorded a ceiling test writedown and reduced the capitalized costs of our oil and gas properties which resulted in a lower DD&A rate beginning in the second quarter of 2009. As a result, our DD&A rate for the first six months of 2009 is the average of the first and second quarter rates of $2.42 per Mcfe and $1.94 per Mcfe, respectively. Since the second quarter of 2009, our DD&A rate per Mcfe has increased primarily due to higher cost reserve additions. Total DD&A expense for the six months ended June 30, 2010, was relatively unchanged from the same period of 2009 as a result of increased production during 2010.

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- G&A expense per Mcfe increased 9% primarily due to increased employee-related expenses associated with our growing domestic workforce. During the first six months of 2010, we capitalized $27 million of direct internal costs as compared to $28 million in the same period of 2009.

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

- Other expenses for the six months ended June 30, 2010, includes the early redemption premium of $12 million associated with the tender of our $175 million aggregate principal amount 7 % Senior Notes due 2011, partially offset by the $2 million cash received resulting from the termination of the associated interest rate swap. Other expenses for the six months ended June 30, 2009 includes long-term rig contract termination fees.

International Operations. Our international operating expenses for the six months ended June 30, 2010, stated on a Mcfe basis, increased 24% over the same period of 2009. The components of the significant period to period change are as follows:

- LOE per Mcfe during 2010 decreased 11% as compared with the same period of 2009 primarily due to lower overall operating and service costs. This decrease was offset by the 13% increase in production volumes and the timing of liftings during 2010 resulting in no change in total LOE expense from the same period of 2009.

- Production and other taxes increased significantly due to substantially higher realized oil prices during 2010.

- The DD&A rate per Mcfe increased 9% primarily due to unsuccessful exploratory drilling efforts in Malaysia and offshore China.

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 gas prices and changes in our outstanding hedging contracts during these periods.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Gross interest expense:				
Credit arrangements	$ 1	$ 2	$ 1	$ 5
Senior notes	—	3	2	6
Senior subordinated notes	37	26	73	51
Other	1	1	1	2
Total gross interest expense	39	32	77	64
Capitalized interest	(16)	(12)	(28)	(26)
Net interest expense	$ 23	$ 20	$ 49	$ 38

The 24% and 21% increases in gross interest expense for the three and six month periods ended June 30, 2010, respectively, as compared to the same periods of 2009 primarily resulted from the issuance of $700 million aggregate principal amount of 6 % Senior Subordinated Notes due 2020 in January 2010, partially offset by the tender of our $175 million aggregate principal amount of 7 % Senior Notes during the first six months of 2010. See Note 9, “Debt,” to our consolidated financial statements appearing earlier in this report.

Taxes. The effective tax rates for the second quarter of 2010 and 2009 were 36.8% and 35.4%, respectively. The effective tax rates for the first six months of 2010 and 2009 were 37.0% and 36.4%, respectively. 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 gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

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Liquidity and Capital Resources

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

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

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

On January 25, 2010, we sold $700 million aggregate principal amount of 6 % Senior Subordinated Notes due 2020 and received net proceeds of $686 million (net of discount and offering costs). These notes were issued at 99.109% of par to yield 7%. We used $294 million of the net proceeds to repay all of our then outstanding borrowings under our credit facility and $215 million to fund the acquisition of assets from TXCO Resources Inc.

During the first six months of 2010, we accepted for purchase and payment our $175 million aggregate principal amount of 7 % Senior Notes due 2011. The tender included the payment of an early redemption premium of $12 million. This premium was recorded under the caption "Operating expenses – Other" on our consolidated statement of income. We funded the tender offer with a portion of the proceeds from our January 25, 2010 Senior Subordinated Notes issuance.

We continue to hold auction rate securities with a fair value of $33 million. We attempt to sell these securities every 7-28 days until the auctions succeed, the issuer calls the securities or the securities mature. We currently do not believe that the decrease in the fair value of these investments is permanent 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. See Note 8, "Fair Value Measurements," for more information regarding the auction rate securities.

Credit Arrangements. We have a revolving credit facility that matures in June 2012 and provides for loan commitments of $1.25 billion from a syndicate of more than 15 financial institutions, led by JPMorgan Chase Bank, as agent. As of June 30, 2010, the largest commitment was 16% of total commitments. However, the amount that we can borrow under the facility could be limited by changing expectations of future oil and gas prices because the maximum amount that we may borrow under the facility is determined by our lenders annually each May (and may be adjusted at the option of our lenders in the case of certain acquisitions or divestitures) using a process that takes into account the value of our estimated reserves and hedge position and the lenders' commodity price assumptions.

In the future, total commitments under the facility could be increased to a maximum of $1.65 billion if the existing lenders increase their individual loan commitments or new financial institutions are added to the facility. We do not believe we could access such additional capacity in the current credit market. In addition, subject to compliance with covenants in our credit facility that restrict our ability to incur additional debt, we also have a total of $105 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 9, “Debt,” to our consolidated financial statements appearing earlier in this report.

At July 20, 2010, we had borrowings of $22 million and no letters of credit outstanding under our $1.25 billion credit facility. Our available borrowing capacity under our credit arrangements was approximately $1.36 billion as of July 20, 2010.

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

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At June 30, 2010, we had negative working capital of $17 million compared to positive working capital of $20 million at December 31, 2009. The decrease in our working capital as compared to December 31, 2009 is primarily a result of the timing of drilling activities, timing of payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations. The decrease was partially offset by an increase of $44 million in our cash balance as of June 30, 2010.

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 gas production under floating price market sensitive contracts. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months. See "—Oil and Gas Hedging" below.

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

Our net cash flows from operations were $888 million for the six months ended June 30, 2010, an increase of 25% compared to net cash flows from operations of $712 million for the same period in 2009. Our working capital requirements during the first six months of 2010 decreased compared to the same period of 2009 as a result of the timing of drilling activities, receivable collections from purchasers, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Cash Flows from Investing Activities. Net cash used in investing activities for the six months ended June 30, 2010 was $974 million compared to $776 million for the same period in 2009.

During the six months ended June 30, 2010, we:

- spent $993 million (including $219 million for acquisitions of oil and gas properties); and
- received proceeds of $14 million from sales of oil and gas properties; and
- redeemed investments of $5 million.

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

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

Capital Expenditures. Our capital spending of $1.0 billion for the first six months of 2010 increased 52% from our capital spending of $664 million during the same period of 2009. These amounts exclude recorded asset retirement obligations of $7 million and $5 million in the 2010 and 2009 periods, respectively. Of the $1.0 billion spent during the first six months of 2010, we invested $559 million in domestic exploitation and development, $90 million in domestic exploration (exclusive of exploitation and leasehold activity), $257 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $103 million outside the United States. Of the $664 million spent during the first six months of 2009, we invested $495 million in domestic exploitation and development, $89 million in domestic exploration (exclusive of exploitation and leasehold activity), $26 million in domestic leasehold activity and $54 million outside the United States.

We have budgeted $1.6 billion for capital spending in 2010 (excluding acquisitions), including $124 million of estimated capitalized interest and overhead. As a result of the continued spread between oil and gas prices, we have re-allocated approximately $200 million of our budget from natural gas projects to oil projects in our portfolio. We currently expect to invest approximately $700 million in oil projects in 2010, or nearly 45% of our total budget. The 2010 capital budget is based on our expectation that we will live within anticipated cash flow from operations (excluding acquisitions). Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

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Cash Flows from Financing Activities. Net cash flows provided by financing activities for the six months ended June 30, 2010 were $130 million compared to $78 million for the same period in 2009.

During the six months ended June 30, 2010, we:

- borrowed $322 million and repaid $707 million under our credit arrangements;
- issued $700 million aggregate principal amount of 6 % Senior Subordinated Notes due 2020 at 99.109% of par and paid $8 million in associated debt issue costs;
- repaid our $175 million aggregate principal amount of 7 % Senior Notes due 2011;
- received proceeds of $17 million from the issuance of shares of our common stock upon the exercise of stock options; and
- repurchased $15 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

During the six months ended June 30, 2009, we borrowed $732 million and repaid $654 million under our credit arrangements.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of June 30, 2010.

	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
Revolving credit facility	$ —	$ —	$ —	$ —	$ —
6 % Senior Subordinated Notes due 2014	325	—	—	325	—
6 % Senior Subordinated Notes due 2016	550	—	—	—	550
7 % Senior Subordinated Notes due 2018	600	—	—	—	600
6 % Senior Subordinated Notes due 2020	700	—	—	—	700
Total debt	2,175	—	—	325	1,850
Other obligations:					
Interest payments	1,138	150	298	286	404
Net derivative (assets) liabilities	(335)	(278)	(57)	—	—
Asset retirement obligations	99	14	10	12	63
Operating leases	108	34	23	22	29
Deferred acquisition payments	2	2	—	—	—
Firm transportation	588	46	134	139	269
Oil and gas activities (1)	111	—	—	—	—
Total other (assets) obligations	1,711	(32)	408	459	765
Total contractual (assets) obligations	$ 3,886	$ (32)	$ 408	$ 784	$ 2,615

(1) As is common in the oil and gas industry, we have various contractual commitments pertaining to exploration, development and production activities. We have work-related commitments for, among other things, drilling wells, obtaining and processing seismic data, natural gas transportation, and fulfilling other cash commitments. At June 30, 2010, these work-related commitments totaled $111 million, all of which were attributable to our international business.

As of June 30, 2010, we have delivery commitments through 2011 to deliver to third party purchasers approximately 100,000 MMBtu of our daily production, principally from our Mid-Continent division. These commitments continue through 2012 at approximately 60,000 MMBtu of our daily production. Given the size of our proved natural gas reserves and production capacity in our Mid-Continent division, we currently believe that we have sufficient reserves and production to fulfill these delivery commitments.

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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 gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and gas prices. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions.

While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate hedging arrangements with that counterparty. At June 30, 2010, Barclays Capital, JPMorgan Chase Bank, N.A., Credit Suisse Energy LLC, Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to 86% of our future hedged production, the largest of which was J Aron & Company and accounted for 25% of our future hedged production.

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

Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. Historically, a majority of our hedged oil and gas 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 natural gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 85-90% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 12 Bcf of our natural gas production from July 2010 through December 2012 to lock in the differential at a weighted average of $0.94 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 $0.93 per MMBtu less than the Henry Hub Index. In the Mid-Continent, we hedged basis associated with approximately 8 Bcf of our anticipated Stiles/Britt Ranch natural gas production from July 2010 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 less than the Henry Hub Index. 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 less than the Henry Hub Index.

The price we receive for our Gulf Coast oil production typically averages about 90-95% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains is currently averaging about $12-$14 per barrel below the WTI price. Oil production from our Mid-Continent properties typically averages 88-92% 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 $4-$6 per barrel less than the WTI price.

New Accounting Requirements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (ASU 2010-03), which aligns the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in the Securities and Exchange Commission's final rule, Modernization of the Oil and Gas Reporting Requirements (Final Rule), which was issued on December 31, 2008 and became effective for the year ended December 31, 2009. We adopted the Final Rule and ASU 2010-03 effective December 31, 2009, as a change in accounting principle that is inseparable from a change in accounting estimate. Such a change is accounted for prospectively under the authoritative accounting guidance. Comparative disclosures applying the new rules for periods before the adoption of ASU 2010-03 and the Final Rule are not required.

In January 2010, the FASB issued additional disclosure requirements related to fair value measurements. The guidance requires disclosure of transfers of assets and liabilities between Level 1 and Level 2 in the fair value measurement hierarchy, including the reasons for the transfers and disclosure of major purchases, sales, issuances, and settlements on a gross basis in the reconciliation of the assets and liabilities measured under Level 3 of the fair value measurement hierarchy. The guidance is effective for interim and annual periods beginning after December 15, 2009, except for the Level 3 reconciliation disclosures which are effective for interim and annual periods beginning after December 15, 2010. We adopted the provisions for the quarter ending March 31, 2010, except for the Level 3 reconciliation disclosures, which we will adopt for the quarter ending March 31, 2011. Adopting the disclosure requirements did not have an impact on our financial position or results of operations. We do not expect adoption of the Level 3 reconciliation disclosures in 2011 to have an impact on our financial position or results of operations.

General Information

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

Our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission.

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Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results, such as planned capital expenditures, the availability and sources 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 impact of governmental regulations;
- the availability and cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;
- the availability of refining capacity for the crude oil we produce from our Monument Butte field;
- drilling results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- labor conditions;
- weather conditions, and changes in weather patterns, including adverse conditions and changes in patterns due to climate change;
- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources; and
- the other factors affecting our business described under the caption “Risk Factors” in Item 1A of our annual report on Form 10-K for the year ended December 31, 2009 and under Item 1A of this report.

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report and in our annual report on Form 10-K for the year ended December 31, 2009. 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.

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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 gas reservoir 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.

Exploration well. An exploration well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

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.

Proved reserves. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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 gas prices, interest rates and foreign currency exchange rates as discussed below.

Oil and 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 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 5, "Derivative Financial Instruments," to our consolidated financial statements appearing earlier in this report.

Interest Rates

At June 30, 2010, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
6 % Senior Subordinated Notes due 2014	$ 325	$ —
6 % Senior Subordinated Notes due 2016	550	—
7 % Senior Subordinated Notes due 2018	600	—
6 % Senior Subordinated Notes due 2020	694	—
Total debt	$ 2,169	$ —

Because 100% of our debt obligations were at fixed rates, we currently do not have exposure to interest rate changes.

Foreign Currency Exchange Rates

The functional currency for all of our foreign operations is the U.S. dollar. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flow, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at June 30, 2010.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2010.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the second quarter of 2010 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 Newfield's legal proceedings previously reported in Newfield's annual report on Form 10-K for the year ended December 31, 2009.

Item 1A. Risk Factors

The following risk factor updates and should be considered in addition to the risk factors previously disclosed in Newfield's annual report on Form 10-K for the year ended December 31, 2009.

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

- the amounts and types of substances and materials that may be released into the environment;
- response to unexpected releases to the environment;
- reports and permits concerning exploration, drilling, production and other operations;
- the spacing of wells;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and

• taxation.

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

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

Congress has been actively considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which is now being considered by the U.S. Senate. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. Further, on April 2, 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an “air pollutant” under the federal Clean Air Act. On April 24, 2009, EPA responded to the Massachusetts, et al. v. EPA decision with a proposed finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change. EPA published the final version of this finding on December 15, 2009, which allowed EPA to proceed with the rulemaking process to regulate greenhouse gases under the Clean Air Act. In anticipation of the finalization of EPA’s finding that greenhouse gases threaten public health and welfare, and that greenhouse gases from new motor vehicles contribute to climate change, EPA proposed a rule in September of 2009 that would require a reduction in emissions of greenhouse gases from motor vehicles and would trigger applicability of Clean Air Act permitting requirements for certain stationary sources of greenhouse gas emissions. In response to this issue, EPA also proposed a tailoring rule that would, in general, only impose greenhouse gas permitting requirements on facilities that emit more than 25,000 tons per year of greenhouse gases. Moreover, on September 22, 2009, EPA finalized a rule requiring nation-wide reporting of greenhouse gas emissions in 2011 for emissions occurring in 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year, and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines.

In response to the recent oil spill in the Gulf of Mexico, the United States Congress is considering a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations governing our operations in the United States, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

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

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended June 30, 2010.

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 Purchase Under the Plans or Programs
April 1 - April 30, 2010	1,706	$ 53.69	—	—
May 1 - May 31, 2010	830	59.32	—	—
June 1 - June 30, 2010	12,737	51.14	—	—
Total	15,273	$ 51.87	—	—

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards and restricted stock units. 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
4.1.1	First Supplemental Indenture, dated as of February 19, 2010, to Senior Indenture dated as of February 28, 2001 between Newfield and U.S. Bank National Association (as successor to First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield's Current Report on Form 8-K filed with the SEC on February 19, 2010 (File No. 1-12534))
4.2.4	Fifth Supplemental Indenture, dated as of January 25, 2010, to Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Newfield's Current Report on Form 8-K filed with the SEC on January 25, 2010 (File No. 1-12534))
10.20	Form of 2010 TSR Restricted Stock Unit Agreement between Newfield and its executive officers dated as of February 4, 2010 (incorporated by reference to Exhibit 10.20 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 1-12534))
10.21	Form of 2010 Restricted Stock Unit Agreement between Newfield and its executive officers dated as of February 4, 2010 (incorporated by reference to Exhibit 10.21 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 1-12534))
10.23	Summary of Non-Employee Director Compensation Program (incorporated by reference to Exhibit 10.23 to Newfield's Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 1-12534))
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

* 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: July 23, 2010	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer

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