NEWFIELD EXPLORATION CO /DE/
Form 10-Q
July 22, 2011

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, 2011

OR

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

For the Transition Period from to .

Commission File Number: 1-12534

NEWFIELD EXPLORATION COMPANY
(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	72-1133047 (I.R.S. Employer Identification Number)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T

(§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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, 2011, there were 134,618,805 shares of the registrant's common stock, par value $0.01 per share, outstanding.

TABLE OF CONTENTS

Table of Contents

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET

(In millions, except share data)

(Unaudited)

	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 74	$ 39
Accounts receivable	360	354
Inventories	106	79
Derivative assets	128	197
Other current assets	80	62
Total current assets	748	731
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($2,167 and $1,658 were excluded from amortization at June 30, 2011 and December 31, 2010, respectively)	13,730	12,399
Less accumulated depreciation, depletion and amortization	(6,166)	(5,791)
Total property and equipment, net	7,564	6,608
Derivative assets	35	39
Long-term investments	53	48
Deferred taxes	33	29
Other assets	48	39
Total assets	$ 8,481	$ 7,494
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 113	$ 92
Accrued liabilities	696	670
Advances from joint owners	55	51
Asset retirement obligation	10	11
Derivative liabilities	65	53
Deferred taxes	22	51
Total current liabilities	961	928
Other liabilities	55	56
Derivative liabilities	69	46
Long-term debt	2,889	2,304
Asset retirement obligation	108	97
Deferred taxes	837	720
Total long-term liabilities	3,958	3,223
Commitments 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, 2011				
and December 31, 2010; 136,285,771 and 135,910,641 shares issued at				
June 30, 2011 and December 31, 2010, respectively)		1		1
Additional paid-in capital		1,472		1,450
Treasury stock (at cost, 1,682,122 and 1,664,538 shares at June 30, 2011 and				
December 31, 2010, respectively)		(50)		(41)
Accumulated other comprehensive loss		(8)		(12)
Retained earnings		2,147		1,945
Total stockholders' equity		3,562		3,343
Total liabilities and stockholders' equity	$	8,481	$	7,494

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

1

Table of Contents

NEWFIELD EXPLORATION COMPANY

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Oil and gas revenues	$621	$448	$1,166	$906
Operating expenses:				
Lease operating	125	84	218	151
Production and other taxes	79	31	150	56
Depreciation, depletion and amortization	173	160	339	307
General and administrative	44	41	81	77
Other	—	2	—	10
Total operating expenses	421	318	788	601
Income from operations	200	130	378	305
Other income (expenses):				
Interest expense	(41)	(39)	(81)	(77)
Capitalized interest	19	16	37	28
Commodity derivative income (expense)	169	46	(13)	283
Other	—	(1)	(1)	1
Total other income (expenses)	147	22	(58)	235
Income before income taxes	347	152	320	540
Income tax provision:				
Current	7	14	30	27
Deferred	121	42	88	173
Total income tax provision	128	56	118	200
Net income	$219	$96	$202	$340
Earnings per share:				
Basic	$1.64	$0.73	$1.52	$2.59
Diluted	$1.62	$0.72	$1.50	$2.55
Weighted-average number of shares outstanding for basic earnings per share	134	132	133	131
Weighted-average number of shares outstanding for diluted earnings per share	135	134	135	133

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

2

Table of Contents

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

	Six Months Ended June 30, 2011	2010
Cash flows from operating activities:		
Net income	$ 202	$ 340
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	339	307
Deferred tax provision	88	173
Stock-based compensation	14	12
Commodity derivative (income) expense	13	(283)
Cash receipts on derivative settlements, net	95	227
Other non-cash charges	3	—
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(6)	11
(Increase) decrease in inventories	(26)	6
(Increase) decrease in other current assets	(19)	29
(Increase) decrease in other assets	(4)	1
Increase in accounts payable and accrued liabilities	29	40
Increase in advances from joint owners	4	19
Increase (decrease) in other liabilities	(3)	6
Net cash provided by operating activities	729	888
Cash flows from investing activities:		
Additions to oil and gas properties	(1,077)	(767)
Acquisitions of oil and gas properties	(311)	(219)
Proceeds from sales of oil and gas properties	130	14
Additions to furniture, fixtures and equipment	(10)	(7)
Redemptions of investments	1	5
Net cash used in investing activities	(1,267)	(974)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	2,371	322
Repayments of borrowings under credit arrangements	(1,786)	(707)
Net proceeds from issuance of senior subordinated notes	—	694
Debt issue costs	(8)	(8)
Repayment of senior notes	—	(175)
Proceeds from issuances of common stock	11	17

Purchases of treasury stock, net		(15)		(13)
Net cash provided by financing activities		573		130
Increase in cash and cash equivalents		35		44
Cash and cash equivalents, beginning of period		39		78
Cash and cash equivalents, end of period	$	74	$	122

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

Table of Contents

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

	Common Stock		Treasury Stock					
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 2010	135.9	$ 1	(1.7)	$ (41)	$ 1,450	$ 1,945	$ (12)	$ 3,343
Issuances of common stock	0.4	—			11			11
Stock-based compensation					17			17
Treasury stock, net			—	(9)	(6)			(15)
Comprehensive income:								
Net income						202		202
Unrealized gain on investments, net of tax of $(2)							4	4
Total comprehensive income								206
Balance, June 30, 2011	136.3	$ 1	(1.7)	$ (50)	$ 1,472	$ 2,147	$ (8)	$ 3,562

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

Table of Contents
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, Appalachia 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, 2010.

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 the fair value of our derivative positions.

Investments

Investments consist primarily of debt and equity securities, as well as auction rate securities, a majority 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 net gains on our investment securities of approximately $0.2 million and $0.4 million for the three months ended June 30, 2011 and 2010, respectively, and $1 million for each of the six month periods ended June 30, 2011 and 2010.

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. Substantially all of the crude oil from our operations offshore Malaysia and China is produced into FPSOs and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 298,000 barrels and 277,000 barrels of crude oil valued at cost of $24 million and $15 million at June 30, 2011 and December 31, 2010, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depletion 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. We capitalized $27 million and $16 million of internal costs during the three months ended June 30, 2011 and 2010, respectively, and $51 million and $36 million during the six months ended June 30, 2011 and 2010, respectively. Interest expense related to unproved properties is also capitalized into oil and gas properties.

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. 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 oil and gas reserve estimation requirements, 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; plus
- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less
- related income tax effects.

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

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

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil and gas prices decrease significantly or if we have substantial downward revisions in our estimated proved reserves. At June 30, 2011, 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 $4.21 per MMBtu for natural gas and $90.02

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, 2011.

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.

Table of Contents

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

The change in our ARO for the six months ended June 30, 2011 is set forth below (in millions):

Balance as of January 1, 2011	$	108
Accretion expense		5
Additions		8
Settlements		(3)
Balance at June 30, 2011		118
Less: Current portion of ARO at June 30, 2011		(10)
Total long-term ARO at June 30, 2011	$	108

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.

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. We also have utilized derivatives to manage our exposure to variable interest rates.

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.

Table of Contents

New Accounting Requirements

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 was 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 ended March 31, 2010, except for the Level 3 reconciliation disclosures, which we adopted for the quarter ended March 31, 2011. Adopting the disclosure requirements did not have a material impact on our financial position or results of operations.

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change will require us, for Level 3 fair value measurements, to disclose quantitative information about unobservable inputs used, a description of the valuation processes used, and a qualitative discussion about the sensitivity of the measurements. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the additional fair value measurement and disclosure requirements to have a material impact on our financial position or results of operations.

In June 2011, the FASB issued guidance impacting the presentation of comprehensive income. The guidance eliminates the current option to report components of other comprehensive income in the statement of changes in equity. The guidance is intended to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the comprehensive income presentation 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 incorporate 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."

Table of Contents

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, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions, except per share data)			
Income (numerator):				
Net income — basic and diluted	$ 219	$ 96	$ 202	$ 340
Weighted-average shares (denominator):				
Weighted-average shares — basic	134	132	133	131
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period (1)	1	2	2	2
Weighted-average shares — diluted	135	134	135	133
Earnings per share:				
Basic	$ 1.64	$ 0.73	$ 1.52	$ 2.59
Diluted	$ 1.62	$ 0.72	$ 1.50	$ 2.55

(1) The calculation of shares outstanding for diluted EPS does not include the effect of one million unvested restricted stock and restricted stock units for each of the six month periods ended June 30, 2011 and 2010, respectively, because to do so would be anti-dilutive.

3. Comprehensive Income:

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Net income	$ 219	$ 96	$ 202	$ 340
Unrealized gain (loss) on investments, net of tax of ($1) and ($2) for the three and six month periods ended June 30, 2011, respectively, and net of tax of $1 for each of the three and six month periods ended June 30, 2010	1	(3)	4	(2)
Total comprehensive income	$ 220	$ 93	$ 206	$ 338

9

Table of Contents

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

4. Oil and Gas Assets:

Property and Equipment

As of the indicated dates, our property and equipment consisted of the following at:

	June 30, 2011	December 31, 2010
	(In millions)	
Oil and gas properties:		
Subject to amortization	$11,439	$10,627
Not subject to amortization	2,167	1,658
Gross oil and gas properties	13,606	12,285
Accumulated depreciation, depletion and amortization	(6,099)	(5,730)
Net oil and gas properties	7,507	6,555
Other property and equipment	124	114
Accumulated depreciation and amortization	(67)	(61)
Net other property and equipment	57	53
Total property and equipment, net	$7,564	$6,608

The following is a summary of our oil and gas properties not subject to amortization as of June 30, 2011. We believe that our evaluation activities related to substantially all of our conventional properties not subject to amortization will be completed within four years. Because of the size of our unconventional resource plays, their entire evaluation will take significantly longer than four years. At June 30, 2011, approximately 70% of oil and gas properties not subject to amortization were associated with our unconventional resource plays.

	Costs Incurred In				
	2011	2010	2009	2008 and prior	Total
			(In millions)		
Acquisition costs	$352	$372	$144	$479	$1,347
Exploration costs	280	86	61	70	497
Development costs	23	32	16	49	120
Fee mineral interests	—	—	—	23	23
Capitalized interest	37	58	51	34	180
Total oil and gas properties not subject to amortization	$692	$548	$272	$655	$2,167

Uinta Basin Asset Acquisitions

On May 17, 2011, we closed two previously announced transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $311 million. The assets include approximately 70,000 net acres which are largely undeveloped and located north of our Greater Monument Butte field.

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

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 realized and unrealized 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.

Table of Contents

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

At June 30, 2011, we had outstanding contracts with respect to our future production that are not designated for hedge accounting as set forth in the tables below.

Natural Gas

		NYMEX Contract Price Per MMBtu								
					Collars					Estimated Fair Value Asset
		Swaps	Additional Put		Floors		Ceilings			
Period and Type of Contract	Volume in MMMBtus	(Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	(Liability) (In millions)
July 2011 – September 2011									
Price swap contracts	24,840	$6.30	—	—	—	—	—	—	$48
3-Way collar contracts	10,120	—	$4.50	$4.50	$6.00	$6.00	$7.75-$8.03	$7.91	14
October 2011 – December 2011									
Price swap contracts	12,030	6.03	—	—	—	—	—	—	18
3-Way collar contracts	17,440	—	4.50	4.50	5.50-6.00	5.86	6.60-8.03	7.37	18
January 2012 – December 2012									
Price swap contracts	18,300	5.42	—	—	—	—	—	—	12
3-Way collar contracts	83,570	—	3.50-4.50	4.28	5.00-6.00	5.49	5.20-7.55	6.36	43
January 2013 – December 2013									
Price swap contracts	18,250	5.33	—	—	—	—	—	—	3

3-Way collar contracts	39,530	—	3.50-4.50	4.04	5.00-6.00	5.44	6.00- 7.55	6.48	13
									$169

Oil

Period and Type of Contract	Volume in MBbls	NYMEX Contract Price Per Bbl: Swaps (Weighted Average)	Collars: Additional Put Range	Additional Put Weighted Average	Floors Range	Floors Weighted Average	Ceilings Range	Ceilings Weighted Average	Estimated Fair Value Asset (Liability) (In millions)
July 2011 – September 2011									
Price swap contracts	920	$81.51	—	—	—	—	—	—	$ (13)
3-Way collar contracts	1,748	—	$60.00-$90.00	$67.63	$75.00-$100.00	$82.37	$102.25-$129.75	$112.28	—
October 2011 – December 2011									
Price swap contracts	920	81.51	—	—	—	—	—	—	(15)
3-Way collar contracts	1,932	—	60.00-90.00	66.90	75.00-100.00	81.67	102.25-129.75	111.68	(3)
January 2012 – December 2012									
Price swap contracts	2,196	82.27	—	—	—	—	—	—	(38)
3-Way collar contracts	10,614	—	55.00-90.00	66.21	75.00-100.00	83.10	106.30-137.80	115.50	(34)
January 2013 –									

December 2013									
3-Way collar contracts	4,745	—	55.00	55.00	80.00	80.00	109.50-111.40	110.54	(25)
									$ (128)

12

Table of Contents

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

Basis Contracts

At June 30, 2011, 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 2011 – September 2011	1,320	$ (0.95)	2,440	$ (0.55)	$ (2)
October 2011 – December 2011	1,320	(0.95)	4,290	(0.55)	(2)
January 2012 – December 2012	4,920	(0.91)	18,300	(0.55)	(8)
					$ (12)

Additional Disclosures about Derivative Instruments and Hedging Activities

We had derivative financial instruments recorded in our balance sheet as assets (liabilities) at their respective estimated fair value, as set forth below.

Type of Contract	Balance Sheet Location	June 30, 2011	December 31, 2010
		(In millions)	
Derivatives not designated as hedging instruments:			
Natural gas contracts	Derivative assets – current	$ 132	$ 201
Oil contracts	Derivative assets – current	—	1
Basis contracts	Derivative assets – current	(4)	(5)
Natural gas contracts	Derivative assets – noncurrent	37	45
Basis contracts	Derivative assets – noncurrent	(2)	(6)
Oil contracts	Derivative liabilities – current	(61)	(53)
Basis contracts	Derivative liabilities – current	(4)	—
Natural gas contracts	Derivative liabilities – noncurrent	—	(4)
Oil contracts	Derivative liabilities – noncurrent	(67)	(42)
Basis contracts	Derivative liabilities – noncurrent	(2)	—
Total		$ 29	$ 137

13

Table of Contents

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

The amount of gain (loss) recognized in income related to our derivative financial instruments is recorded under "Commodity derivative income (expense)" in our income statement, as follows:

Type of Contract	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)			
Derivatives not designated as hedging instruments:				
Realized gain on natural gas contracts	$62	$81	$130	$144
Realized gain (loss) on oil contracts	(20)	37	(32)	71
Realized loss on basis contracts	(2)	(1)	(3)	(3)
Total realized gain	40	117	95	212
Unrealized gain (loss) on natural gas contracts	(19)	(110)	(73)	80
Unrealized gain (loss) on oil contracts	148	33	(35)	(12)
Unrealized gain on basis contracts	—	6	—	3
Total unrealized gain (loss)	129	(71)	(108)	71
Total commodity derivative income (expense)	$169	$46	$(13)	$283

The total realized gain on commodity derivatives for the three and six months ended June 30, 2010 differs from the cash receipts on derivative settlements due to the recognition of option premiums associated with derivatives settled during the period. There were no option premiums recognized during the three and six months ended June 30, 2011.

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, 2011, Barclays Capital, Morgan Stanley, JPMorgan Chase Bank, N.A., Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to 85% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

The counterparties to the majority of 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, 2011	December 31, 2010
	(In millions)	
Revenue	$209	$199
Joint interest	136	133

Other	16	23
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$360	$354

Table of Contents

7. Accrued Liabilities:

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

	June 30, 2011	December 31, 2010
	(In millions)	
Revenue payable	$80	$69
Accrued capital costs	332	327
Accrued lease operating expenses	73	54
Employee incentive expense	42	59
Accrued interest on debt	41	41
Taxes payable	100	81
Other	28	39
Total accrued liabilities	$696	$670

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 and certain investments.

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 options including, price collars, floors and three-way collars (as of June 30, 2011, our options were comprised of only three-way collars) 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.

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, 2010:				
Investments available-for-sale:				
Equity securities	$7	$—	$ —	$7
Auction rate securities	—	—	30	30
Oil and gas derivative swap contracts	—	89	(11)	78
Oil and gas derivative option contracts	—	—	59	59
Total	$7	$89	$ 78	$174
As of June 30, 2011:				
Investments available-for-sale:				
Equity securities	$8	$—	$ —	$8
Auction rate securities	—	—	35	35
Oil and gas derivative swap contracts	—	15	(12)	3
Oil and gas derivative option contracts	—	—	26	26
Total	$8	$15	$ 49	$72

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, 2011, we continued to hold $35 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 $12 million ($8 million net of tax), recorded under the caption “Accumulated other comprehensive loss” on our consolidated balance sheet. As of December 31, 2010, we held $30 million of auction rate securities, which reflected a decrease in the fair value of $17 million ($11 million net of tax). The debt instruments underlying our auction rate securities 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.

Table of Contents

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, 2010	$40	$159	$199
Total realized or unrealized gains (losses):			
Included in earnings	—	43	43
Included in other comprehensive 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 included in earnings relating to investments and derivatives still held at June 30, 2010	$—	$53	$53
Balance at January 1, 2011	$30	$48	$78
Total realized or unrealized gains (losses):			
Included in earnings	—	(8)	(8)
Included in other comprehensive income	5	—	5
Purchases, issuances and settlements:			
Settlements	—	(26)	(26)
Transfers in and out of Level 3	—	—	—
Balance at June 30, 2011	$35	$14	$49
Change in unrealized losses included in earnings relating to investments and derivatives still held at June 30, 2011	$—	$(12)	$(12)

Fair Value of Debt

The estimated fair value of our notes, based on quoted market prices as of the indicated dates, was as follows:

	June 30, 2011	December 31, 2010
	(In millions)	
6 % Senior Subordinated Notes due 2014	$328	$333
6 % Senior Subordinated Notes due 2016	569	568
7 % Senior Subordinated Notes due 2018	635	626
6 % Senior Subordinated Notes due 2020	739	733

Amounts outstanding under our credit arrangements at June 30, 2011 and December 31, 2010 are stated at cost, which approximates fair value. Please see Note 9, "Debt."

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

9. Debt:

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

	June 30, 2011	December 31, 2010
	(In millions)	
Senior unsecured debt:		
Revolving credit facility LIBOR based loans	$720	$100
Money market lines of credit(1)	—	35
Total senior unsecured debt	720	135
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	694
Total long-term debt	$2,889	$2,304

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

Credit Arrangements

In June 2011, we entered into a new revolving credit facility that matures in June 2016. This facility replaces our previous facility. The terms of the credit facility provide for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, as agent. As of June 30, 2011, the largest individual loan commitment by any lender was 13% of total commitments.

Loans under the new 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, plus a margin that is based on a grid of our debt rating (75 basis points per annum at June 30, 2011) or (b) the London Interbank Offered Rate, plus a margin that is based on a grid of our debt rating (175 basis points per annum at June 30, 2011).

Under our new credit facility and our previous credit facility, we pay commitment fees on available but undrawn amounts based on a grid of our debt rating (30 basis points per annum at June 30, 2011). We incurred fees under these arrangements of approximately $0.4 million and $0.8 million for the three and six months ended June 30, 2011, respectively, which are recorded in interest expense on our consolidated statement of income. For the three and six months ended June 30, 2010, we incurred commitment fees of approximately $0.5 million and $1 million, respectively.

Our new 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 and maintenance of a ratio of 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) to interest expense of at least 3.0 to 1.0. At June 30, 2011, we were in compliance with all of our debt covenants.

Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at June 30, 2011). As of June 30, 2011, we had no letters of credit outstanding under our credit facility.

Subject to compliance with the restrictive covenants in our credit facility, as of June 30, 2011, 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.

Table of Contents

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

The credit facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; inaccuracy of representations and warranties in any material respect; a change of control; or certain other material adverse changes in our business. Our senior subordinated notes also contain standard events of default. If any of the foregoing defaults were to occur, our lenders under the credit facility could terminate future lending commitments and our lenders under both the credit facility and our notes 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.

10. Income Taxes:

The provision 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,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Amount computed using the statutory rate	$ 121	$ 53	$ 112	$ 189
Increase in taxes resulting from:				
State and local income taxes, net of federal effect	7	2	5	8
Net effect of different tax rates in non-U.S. jurisdictions	—	1	1	3
Total provision for income taxes	$ 128	$ 56	$ 118	$ 200

As of June 30, 2011, we had net operating loss (NOL) carryforwards for international income tax purposes of approximately $25 million. We currently estimate that we will not be able to utilize $17 million of our international NOLs because we do not have sufficient estimated future taxable income in the appropriate jurisdictions. Therefore, valuation allowances were established for these items in 2005 and 2006. The remaining $8 million will expire in 2013. 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.

As of June 30, 2011, we did not have a liability for uncertain tax positions and as such we had not accrued related interest or penalties. The tax years 2007-2010 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

11. Stock-Based Compensation:

On May 5, 2011, at our 2011 annual meeting of stockholders, our stockholders approved the Newfield Exploration Company 2011 Omnibus Stock Plan (the 2011 Omnibus Stock Plan), and our 2009 Omnibus Stock Plan and 2009 Non-Employee Director Restricted Stock Plan were terminated such that no new grants will be made under the previous plans. All stock-based compensation equity awards to employees and non-employee directors will be granted under the 2011 Omnibus Stock Plan. Outstanding awards under those previous plans were not impacted by the termination of those previous plans. The fair value of grants is 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. In February 2011, we also granted cash-settled restricted stock units to employees which were not issued under any of our plans as they will be settled in cash upon vesting and are accounted for as liability awards.

As of the indicated dates, our stock-based compensation for our equity and liability awards consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Total stock-based compensation	$ 11	$ 9	$ 19	$ 18
Capitalized in oil and gas properties	(3)	(3)	(5)	(6)
Net stock-based compensation expense	$ 8	$ 6	$ 14	$ 12

Table of Contents

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

As of June 30, 2011, we had approximately $80 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation equity 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.

Stock Options. The following table provides information about stock option activity for the six months ended June 30, 2011:

	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, 2010	1.5	$34.58		4.7	$58
Granted	—	—	$—		
Exercised	(0.4)	30.04			15
Forfeited	—	—			
Outstanding at June 30, 2011	1.1	$35.83		4.4	$39
Exercisable at June 30, 2011	1.0	$33.69		4.0	$35

(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, 2011, the last reported sales price of our common stock on the New York Stock Exchange was $68.02 per share.

Restricted Stock. The following table provides information about equity-classified restricted stock and restricted stock unit activity for the six months ended June 30, 2011:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted-Average Grant Date Fair Value per Share
	(In millions, except per share data)			
Non-vested shares outstanding at December 31, 2010	2.2	0.3	2.5	$ 36.84
Granted	0.6	0.1	0.7	67.29
Forfeited	(0.1)	—	(0.1)	41.73
Vested	(0.7)	(0.1)	(0.8)	33.52
Non-vested shares outstanding at June 30, 2011	2.0	0.3	2.3	$ 47.09

Cash-Settled Restricted Stock Units. On February 11, 2011, we granted 148,865 cash-settled restricted stock units to employees which vest over three years.

Employee Stock Purchase Plan. During the first six months of 2011, options to purchase 34,073 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $17.13 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 0.19%, an expected life of six months and weighted-average volatility of 31%.

Table of Contents

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 for the three and six months ended June 30, 2011 and 2010. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

Three Months Ended June 30, 2011:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Oil and gas revenues	$475	$123	$23	$ —	$621
Operating expenses:					
Lease operating	90	33	2	—	125
Production and other taxes	22	51	6	—	79
Depreciation, depletion and amortization	149	19	5	—	173
General and administrative	43	1	—	—	44
Allocated income taxes	64	7	2	—	
Net income from oil and gas properties	$107	$12	$8	$ —	
Total operating expenses					421
Income from operations					200
Interest expense, net of interest income, capitalized interest and other					(22)
Commodity derivative income					169
Income before income taxes					$347
Total assets	$7,480	$772	$229	$ —	$8,481
Additions to long-lived assets	$836	$86	$25	$ —	$947

Table of Contents

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

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 taxes					$152
Total assets	$6,206	$604	$198	$ —	$7,008
Additions to long-lived assets	$389	$39	$17	$ —	$445

Six Months Ended June 30, 2011:

	Domestic	Malaysia	China	Other International	Total
			(In millions)		
Oil and gas revenues	$869	$257	$40	$ —	$1,166
Operating expenses:					
Lease operating	167	48	3	—	218
Production and other taxes	37	102	11	—	150
Depreciation, depletion and amortization	286	44	9	—	339
General and administrative	79	2	—	—	81
Allocated income taxes	111	23	4	—	
Net income from oil and gas properties	$189	$38	$13	$ —	
Total operating expenses					788
Income from operations					378
Interest expense, net of interest income, capitalized interest and other					(45)
Commodity derivative expense					(13)

Income before income taxes					$320
Total assets	$7,480	$772	$229	$ —	$8,481
Additions to long-lived assets	$1,261	$127	$35	$ —	$1,423

Table of Contents

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

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 taxes					$540
Total assets	$6,206	$604	$198	$ —	$7,008
Additions to long-lived assets	$916	$81	$25	$ —	$1,022

Table of Contents

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, Appalachia 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, 2010 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.

Table of Contents

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, 2011, we had net derivative assets of $29 million, of which 49% 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. As a result, the value of these contracts at their respective settlement dates could be significantly different than the fair value as of June 30, 2011. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. Please see "— Critical Accounting Policies and Estimates — Commodity Derivative Activities" in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2010, and 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, 2010 for a discussion 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 $621 million for the second quarter of 2011 were 39% higher than the comparable period of 2010. Revenues of $1.2 billion for the first six months of 2011 were 29% higher than the comparable period of 2010. The revenue increase for both periods is due to higher average realized oil and gas prices.

Table of Contents

The following table summarizes production and average realized prices by product and by geographic area for the three and six month periods ended June 30, 2011 and 2010.

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Percentage Increase (Decrease)	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Percentage Increase (Decrease)
Production:(1)(2)						
Domestic:						
Natural gas (Bcf)	45.4	47.7	(5) %	89.0	92.2	(3) %
Oil, condensate and NGLs (MBbls)	3,142	2,524	24 %	6,015	4,681	28 %
Total (Bcfe)	64.3	62.9	2 %	125.1	120.3	4 %
International:						
Natural gas (Bcf)	—	—	—	—	—	—
Oil, condensate and NGLs (MBbls)	1,227	1,491	(18) %	2,719	2,893	(6) %
Total (Bcfe)	7.3	8.9	(18) %	16.3	17.3	(6) %
Total:						
Natural gas (Bcf)	45.4	47.7	(5) %	89.0	92.2	(3) %
Oil, condensate and NGLs (MBbls)	4,369	4,015	9 %	8,734	7,574	15 %
Total (Bcfe)	71.6	71.8	—	141.4	137.6	3 %
Average Realized Prices:(2)(3)						
Domestic:						
Natural gas (per Mcf)	$ 4.42	$ 3.73	18 %	$ 4.21	$ 4.31	(2)%
Oil, condensate and NGLs (MBbls)	87.03	63.23	38 %	81.68	63.74	28 %
Natural gas equivalent (per Mcfe)	7.40	5.39	37 %	6.95	5.81	20 %
International:						
Natural gas (per Mcf)	$ —	$ —	—	$ —	$ —	—
Oil, condensate and NGLs (MBbls)	118.72	72.90	63 %	109.12	71.74	52 %
Natural gas equivalent (per Mcfe)	19.79	12.15	63 %	18.19	11.96	52 %
Total:						
Natural gas (per Mcf)	$ 4.42	$ 3.73	18 %	$ 4.21	$ 4.31	(2)%
Oil, condensate and NGLs (MBbls)	95.94	66.82	44 %	90.23	66.79	35 %
Natural gas equivalent (per Mcfe)	8.68	6.23	39 %	8.25	6.58	25 %

---

(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in our operations of 1.6 Bcfe and 1.1 Bcfe during the during the three months ended June 30, 2011 and 2010, respectively, and 3.3 Bcfe and 2.3 Bcfe during the six months ended June 30, 2011 and 2010, respectively.

(2) Historically, natural gas liquids (NGLs) volumes have been reported in natural gas production volumes. Effective January 1, 2011, NGLs are reported in barrels and included with total oil and condensate production. As such, all production volumes and average realized prices for periods prior to 2011 have been reclassified for comparability between periods.

(3) Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been \$5.77 and \$5.40 per Mcf for the three months ended June 30, 2011 and 2010, respectively, and \$5.64 and \$5.84 per Mcf for the six months ended June 30, 2011 and 2010, respectively. Our total oil and condensate average realized price would have been \$91.16 and \$76.01 per Bbl for the three months ended June 30, 2011 and 2010, respectively, and \$86.51 and \$76.10 per Bbl for the six months ended June 30, 2011 and 2010, respectively.

Domestic Production. Our three and six months ended June 30, 2011 domestic oil and gas production, stated on a natural gas equivalent basis, increased over the comparable period of 2010 primarily due to increased production in our Rocky Mountain and Gulf of Mexico divisions 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, 2011 international oil production, stated on a natural gas equivalent basis, decreased over the comparable periods of 2010 primarily due to the timing of liftings in Malaysia.

Table of Contents

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, 2011 and 2010.

	Unit-of-Production Three Months Ended June 30, (Per Mcfe)		Percentage Increase (Decrease)	Total Amount Three Months Ended June 30, (In millions)		Percentage Increase (Decrease)
	2011	2010		2011	2010	
Domestic:						
Lease operating	$1.41	$1.14	24 %	$90	$71	27 %
Production and other taxes	0.34	0.24	42 %	22	15	46 %
Depreciation, depletion and amortization	2.32	2.02	15 %	149	128	17 %
General and administrative	0.66	0.61	8 %	43	39	11 %
Other	—	0.03	(100)%	—	2	(100)%
Total operating expenses	4.73	4.04	17 %	304	255	20 %
International:						
Lease operating	$4.58	$1.44	218 %	$35	$13	161 %
Production and other taxes	7.73	1.80	329 %	57	16	253 %
Depreciation, depletion and amortization	3.35	3.61	(7)%	24	32	(24)%
General and administrative	0.24	0.28	(14)%	1	2	(30)%
Total operating expenses	15.88	7.13	123 %	117	63	83 %
Total:						
Lease operating	$1.74	$1.18	47 %	$125	$84	47 %
Production and other taxes	1.10	0.43	156 %	79	31	153 %
Depreciation, depletion and amortization	2.42	2.22	9 %	173	160	9 %
General and administrative	0.62	0.57	9 %	44	41	8 %
Other	—	0.02	(100)%	—	2	(100)%
Total operating expenses	5.88	4.42	33 %	421	318	33 %

Domestic Operations. Our domestic operating expenses for the three months ended June 30, 2011, stated on a Mcfe basis, increased 17% over the same period of 2010. The components of the significant period-to-period change are as follows:

- Lease operating expense (LOE) per Mcfe increased primarily due to an increase in overall operating and service costs and weather-related costs in our Rocky Mountain division and increased transportation costs resulting from the commencement of firm transportation contracts in our Mid-Continent division throughout 2010.

- Production and other taxes per Mcfe increased primarily due to higher realized commodity prices during 2011.

- Since late 2009, the shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our depreciation, depletion and amortization (DD&A) rate. The increase in total DD&A expense is related to the increase in the DD&A rate, coupled with the 2% increase in our production volumes during the second quarter of 2011 compared to the same period of 2010.

- General and administrative (G&A) expense per Mcfe increased primarily due to employee-related expenses associated with our growing domestic work force. During the second quarter of 2011 we capitalized $19 million of direct internal costs as compared to $11 million during the second quarter of 2010.

Table of Contents

International Operations. Our international operating expenses for the three months ended June 30, 2011, stated on a Mcfe basis, increased 123% over the same period of 2010. The components of the significant period-to-period change are as follows:

- The increase in LOE per Mcfe and total LOE is primarily due to $18 million of repair-related activities in Malaysia during the second quarter of 2011.

- Production and other taxes per Mcfe increased significantly due to an increase, per the terms of our production sharing contracts (PSCs), in the tax rate per barrel of oil lifted and sold as a result of substantially higher realized oil prices during the second quarter of 2011.

The following table presents information about our operating expenses for the six months ended June 30, 2011 and 2010.

	Unit-of-Production			Total Amount		
	Six Months Ended June 30,		Percentage Increase (Decrease)	Six Months Ended June 30,		Percentage Increase (Decrease)
	2011	2010		2011	2010	
	(Per Mcfe)			(In millions)		
Domestic:						
Lease operating	$1.34	$1.06	26 %	$167	$127	31 %
Production and other taxes	0.30	0.25	20 %	37	30	23 %
Depreciation, depletion and amortization	2.29	2.01	14 %	286	243	18 %
General and administrative	0.63	0.62	2 %	79	73	7 %
Other	—	0.08	(100)%	—	10	(100)%
Total operating expenses	4.56	4.02	13 %	569	483	18 %
International:						
Lease operating	$3.10	$1.39	123 %	$51	$24	109 %
Production and other taxes	6.89	1.46	372 %	113	26	342 %
Depreciation, depletion and amortization	3.26	3.71	(12)%	53	64	(17)%
General and administrative	0.15	0.20	(25)%	2	4	(28)%
Total operating expenses	13.40	6.76	98 %	219	118	86 %
Total:						
Lease operating	$1.54	$1.10	40 %	$218	$151	44 %
Production and other taxes	1.06	0.41	159 %	150	56	168 %
Depreciation, depletion and amortization	2.40	2.23	8 %	339	307	11 %
General and administrative	0.58	0.56	4 %	81	77	5 %
Other	—	0.07	(100)%	—	10	(100)%
Total operating expenses	5.58	4.37	28 %	788	601	31 %

Domestic Operations. Our domestic operating expenses for the six months ended June 30, 2011, stated on a Mcfe basis, increased 13% over the same period of 2010. The components of the significant period-to-period change are as follows:

-

LOE per Mcfe increased primarily due to an increase in overall operating and service costs and weather-related costs in our Rocky Mountain division and increased transportation costs resulting from the commencement of firm transportation contracts in our Mid-Continent division throughout 2010.

- Production and other taxes per Mcfe increased primarily due to higher realized commodity prices during 2011.
- Since late 2009, the shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our DD&A rate. The increase in total DD&A expense is related to the increase in the DD&A rate, coupled with the 4% increase in our production volumes during the first six months of 2011 compared to the same period of 2010.

Table of Contents

- G&A expense per Mcfe increased primarily due to employee-related expenses associated with our growing domestic work force. During the six months ended June 30, 2011, we capitalized $38 million of direct internal costs as compared to $27 million in the same period of 2010.

International Operations. Our international operating expenses for the six months ended June 30, 2011, stated on a Mcfe basis, increased 98% over the same period of 2010. The components of the significant period-to-period change are as follows:

- LOE per Mcfe increased primarily due to repair-related activities in Malaysia, fixed production costs associated with certain of our PSCs in Malaysia and increase in overall operating and service costs from the various PSCs during the first six months of 2011 compared to the same period of 2010.

- Production and other taxes per Mcfe increased significantly due to an increase, per the terms of the PSCs, in the tax rate per barrel of oil lifted and sold as a result of substantially higher realized oil prices during the first six months of 2011.

Commodity Derivative Income (Expense). The significant fluctuations in commodity derivative income (expense) from period to period is due to the significant 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,	
	2011	2010	2011	2010
	(In millions)			
Gross interest expense:				
Credit arrangements	$3	$1	$4	$1
Senior notes	—	—	—	2
Senior subordinated notes	38	37	76	73
Other	—	1	1	1
Total gross interest expense	41	39	81	77
Capitalized interest	(19)	(16)	(37)	(28)
Net interest expense	$22	$23	$44	$49

Net interest expense decreased $1 million and $5 million for the three and six months ended June 30, 2011, respectively, as compared to the same periods of 2010, primarily due to an increase in capitalized interest, partially offset by an increase in interest expense as a result of increased borrowings under our credit arrangements. Interest expense related to unproved properties is capitalized into oil and gas properties. Capitalized interest increased in 2011 as compared to the same periods of 2010 due to an increase in the average balance of unproved properties.

Taxes. The effective tax rate for both the second quarter of 2011 and 2010 and the first six months of 2011 and 2010 was 37%. Our effective tax rate generally approximates 37%.

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

Liquidity and Capital Resources

Overview. We must find new, and develop existing, reserves to maintain and grow our production and cash flows, which we accomplish through successful drilling programs and the acquisition of oil and gas properties. These activities require substantial capital expenditures. Lower prices for oil and gas, or higher operating costs, may reduce the amount of oil and gas that we can economically produce, and can also affect the amount of cash flows available for capital expenditures.

In addition to operating cash flows, we also may utilize available borrowing capacity under our credit arrangements, or the proceeds from the sale of non-strategic assets for liquidity and capital resource needs. We continuously monitor our liquidity needs, coordinate our capital expenditure programs with expected cash flows, and evaluate available funding alternatives in light of both current and expected conditions. We believe the liquidity and capital resource alternatives to us, combined with our operating cash flows, will be adequate to fund our short-term and foreseeable long-term operations, including our capital expenditure program.

Capital Budget. We establish a capital budget at the beginning of each calendar year. Our 2011 capital budget (excluding acquisitions) approximated our estimate of 2011 cash flows from operations. Approximately 77% of our expected 2011 domestic oil and gas production supporting this estimate is hedged. Our 2011 capital budget, excluding capitalized interest and overhead of $172 million, is approximately $1.9 billion and focuses on projects we believe will generate and lay the foundation for oil production growth in 2011 and thereafter. Accordingly, approximately two-thirds of the 2011 budget will be allocated to oil projects and substantially all the remainder is planned for “liquids rich” gas plays.

Table of Contents

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 May 17, 2011, we closed two previously announced transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $311 million. The acquisitions were funded with borrowings under our credit facility.

We began a program to sell non-strategic assets at the beginning of the year and are utilizing the proceeds to supplement our 2011 cash flows from operations. During the first six months of 2011, we received proceeds from property sales of approximately $130 million. We used the proceeds from these sales to reduce borrowings outstanding under our credit facility. We continue to market and sell other certain non-strategic domestic assets.

We continue to hold auction rate securities with a fair value of $35 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. In June 2011, we entered into a new revolving credit facility that matures in June 2016 and provides for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, as agent. This facility replaces our previous facility. As of June 30, 2011, the largest individual commitment was 13% of total commitments.

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, 2011, we had no letters of credit outstanding under our credit facility. We had outstanding borrowings of $780 million under our credit facility and $46 million under our money market lines of credit. Our available borrowing capacity under our credit arrangements was approximately $540 million as of July 20, 2011.

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. We may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

At June 30, 2011, we had negative working capital of $213 million compared to negative working capital of $197 million at December 31, 2010. The decrease in our working capital as compared to December 31, 2010 is primarily a result of changes in our current net derivative position due to volatility in commodity prices. In addition, the timing of the collection of receivables, drilling activities, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations contributed to the change.

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.

Table of Contents

Our net cash flows from operations were $730 million for the six months ended June 30, 2011, a decrease of $158 million compared to net cash flows from operations of $888 million for the same period in 2010. The decrease results from changes in our working capital requirements as a result of the timing of drilling activities, receivable collections from purchasers and joint interest partners, payments made by us to vendors and other operators, the timing and amount of advances received from our joint operations and a decrease in net cash receipts on derivative settlements.

Cash Flows from Investing Activities. Net cash used in investing activities for the six months ended June 30, 2011 was $1.3 billion compared to $1.0 billion for the same period in 2010.

During the six months ended June 30, 2011, we:

- spent $1.4 billion (including $311 million for acquisitions of oil and gas properties);
- received proceeds of $130 million from sales of oil and gas properties; and
- redeemed investments of $1 million.

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

- spent $1 billion (including $219 million for acquisitions of oil and gas properties);
- received proceeds of $14 million from sales of oil and gas properties; and
- redeemed investments of $5 million.

Capital Expenditures. Our capital spending of $1.4 billion for the first six months of 2011 increased 39% from our capital spending of $1.0 billion during the same period of 2010. These amounts exclude recorded asset retirement obligations of $8 million and $7 million in the 2011 and 2010 periods, respectively. Of the $1.4 billion spent during the first six months of 2011, we invested $750 million in domestic exploitation and development, $114 million in domestic exploration (exclusive of exploitation and leasehold activity), $386 million in acquisitions of proved and unproved property (leasehold) and domestic leasing activity and $155 million outside the United States. 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.

We have budgeted $1.9 billion for capital spending in 2011. The planned budget excludes capitalized interest and overhead of $172 million. Approximately two-thirds of the 2011 budget will be allocated to oil projects and substantially all of the remainder is planned for “liquids rich” gas plays. The 2011 capital budget is based on our expectation that we will live within anticipated cash flows 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.

On May 17, 2011 we closed two previously announced transactions to acquire assets in the Uinta Basin of Utah for a total of approximately $311 million. The assets include approximately 70,000 net acres which are largely undeveloped and located north of our Greater Monument Butte field.

Cash Flows from Financing Activities. Net cash flows provided by financing activities for the six months ended June 30, 2011 were $573 million compared to $130 million for the same period in 2010.

During the six months ended June 30, 2011, we:

- borrowed $2.4 billion and repaid $1.8 billion under our credit arrangements;
- paid $8 million in debt issue costs associated with our new credit facility;

Table of Contents

- received proceeds of $11 million from the issuance of shares of our common stock upon the exercise of stock options; and
- repurchased $17 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, 2010, we:

- borrowed $322 million and repaid $707 million under our credit arrangements;
- issued $700 million aggregate principal amount of our 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 7 % Senior Notes due 2011;
- 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; and
- received proceeds of $17 million from the issuance of shares of our common stock upon the exercise of stock options.

Table of Contents

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of June 30, 2011.

	Total	Less than 1 Year	2-3 Years	4-5 Years	More than 5 Years
			(In millions)		
Debt:					
Revolving credit facility	$720	$—	$—	$720	$—
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	2,895	—	—	1,595	1,300
Other obligations:					
Interest payments (1)	1,050	161	323	289	277
Net derivative (assets) liabilities	(29)	(63)	34	—	—
Asset retirement obligations	118	10	25	14	69
Operating leases (2)	493	93	301	56	43
Deferred acquisition payments	2	2	—	—	—
Firm transportation	571	65	146	139	221
Oil and gas activities (3)	15	—	—	—	—
Total other obligations	2,220	268	829	498	610
Total contractual obligations	$5,115	$268	$829	$2,093	$1,910

(1) Interest associated with our revolving credit facility was calculated using a weighted-average interest rate of 1.75% at June 30, 2011 and is included through the maturity of the facility.

(2) Includes non-cancellable agreements for office space and cancellable agreements for drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for hydraulic well fracturing services and drilling rigs and are included at the gross contractual value. Due to our various working interests where these service contracts will be utilized, it is not feasible to estimate a net contractual obligation. Net payments under these contracts are accounted for as capital additions to our oil and gas properties and could be significantly less than the gross obligation disclosed.

(3) 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, 2011, these work-related commitments totaled $15 million, all of which were attributable to our international business. Actual amounts by maturity are not included because their timing cannot be accurately predicted.

We have various oil and gas production volume delivery commitments that are related to our domestic operations. Given the size of our proved natural gas and oil reserves and production capacity in the respective divisions, we currently believe that we have sufficient reserves and production to fulfill these commitments. See Items 1 and 2, “Business and Properties” in our Annual Report on Form 10-K for the year ended December 31, 2010 for a description of our production and proved reserves. As of June 30, 2011, our delivery commitments through 2021 were as follows:

	Total	Less than	1-3 Years	4-5 Years	More than

		1 Year			5 Years
Gas (MMMBtus)	37,956	28,756	9,200	—	—
Oil (MBbls)	10,505	915	3,190	3,655	2,745

33

Table of Contents

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, 2011, Barclays Capital, Morgan Stanley, JPMorgan Chase Bank, Bank of Montreal, J Aron & Company and Societe Generale were the counterparties with respect to 85% of our future hedged production, none of which were counterparty to more than 25% of our future hedged production.

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

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 90-95% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 7 Bcf of our natural gas production from July 2011 through December 2012 to lock in the differential at a weighted average of $0.92 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 $0.92 per MMBtu less than the Henry Hub Index. In the Mid-Continent, we hedged basis associated with approximately 1 Bcf of our anticipated Stiles/Britt Ranch natural gas production from July 2011 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, excluding NGLs, typically averages about 98-102% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains, excluding NGLs, is currently averaging about $15-$17 per barrel below the WTI price. Oil production from our Mid-Continent properties, excluding NGLs, typically averages 90-95% of the WTI price. Oil sales from our operations in Malaysia typically sell at a slight discount to Tapis, or about 110-115% of WTI. Oil sales from our operations in China typically sell at a premium of up to $10 per barrel greater than the WTI price.

Please see the discussion and tables in Note 5, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report for a description of the accounting applicable to our hedging program, a listing of open contracts as of June 30, 2011 and the estimated fair market value of those contracts as of that date.

New Accounting Requirements

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 was 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 ended March 31, 2010, except for the Level 3 reconciliation disclosures, which we adopted for the quarter ended March 31, 2011. Adopting the disclosure requirements did not have a material impact on our financial position or results of operations.

In May 2011, the FASB issued additional guidance regarding fair value measurement and disclosure requirements. The most significant change will require us, for Level 3 fair value measurements, to disclose quantitative information about unobservable inputs used, a description of the valuation processes used, and a qualitative discussion about the sensitivity of the measurements. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the additional fair value measurement and disclosure requirements to have a material impact on our financial position or results of operations.

In June 2011, the FASB issued guidance impacting the presentation of comprehensive income. The guidance eliminates the current option to report components of other comprehensive income in the statement of changes in equity. The guidance is intended to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. The guidance is effective for interim and annual periods beginning on or after December 15, 2011. We do not expect adoption of the comprehensive income presentation to have an impact on our financial position or results of operations.

Table of Contents

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.

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 legislation and governmental regulations;
- the impact of regulatory approvals;
- the availability of the securities, capital or credit markets and the 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;

- environmental liabilities that are not covered by an effective indemnity or insurance;
- changes in tax rates;
- changes in estimates of reserves;
- 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, 2010.

Table of Contents

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, 2010. 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. Unless securities laws require us to do so, we do not undertake any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

Commonly Used Oil and Gas Terms

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

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

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.

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.

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.

Table of Contents

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, 2011, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility	$—	$720
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	$720

We consider our interest rate exposure to be minimal because approximately 75% of our obligations were at fixed rates. Our variable rate debt is currently at interest rates of less than 2%.

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, 2011.

Table of Contents

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, 2011.

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 2011 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 the legal proceedings previously reported in our Annual Report on Form 10-K for the year ended December 31, 2010.

Item 1A. Risk Factors

There have been no material changes with respect to the risk factors previously reported in our Annual Report on Form 10-K for the year ended December 31, 2010.

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, 2011.

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
April 1 - April 30, 2011	2,653	$ 72.72	—	—

May 1 - May 31, 2011	2,923	68.35	—	—
June 1 - June 30, 2011	4,687	73.01	—	—
Total	10,263	$ 71.61	—	—

(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.

Table of Contents

Item 6. Exhibits

Exhibit Number	Description
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield's Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield's Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield's Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
3.2	Amended and Restated Bylaws of Newfield (incorporated by reference to Exhibit 3.2 to Newfield's Current Report on Form 8-K filed with the SEC on February 6, 2009 (File No. 1-12534))
*10.1	Credit Agreement, dated as of June 2, 2011, by and among Newfield Exploration Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, and BBVA Compass, The Bank of Tokyo-Mitsubishi UFJ, Ltd., and DNB Nor Bank ASA, as Co-Documentation Agents, and other Lenders thereto
†10.2	Newfield Exploration Company 2011 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield's Registration Statement on Form S-8 (Reg. No. 333-173964) filed with the SEC on May 5, 2011)
†*10.3	Form of Executive Officer Restricted Stock Unit Award Agreement under 2011 Omnibus Stock Plan
†*10.4	Form of Executive Officer TSR Restricted Stock Unit Award Agreement under 2011 Omnibus Stock Plan
†*10.5	Form of Independent Director Restricted Stock Award Agreement under 2011 Omnibus Stock Plan
*31.1	Certification of Chief Executive Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	

	Certification of Chief Financial Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
**101.INS	XBRL Instance Document
**101.SCH	XBRL Schema Document
**101.CAL	XBRL Calculation Linkbase Document
**101.LAB	XBRL Label Linkbase Document
**101.PRE	XBRL Presentation Linkbase Document
**101.DEF	XBRL Definition Linkbase Document

* Filed or furnished herewith.
** Furnished herewith.
† Identifies management contracts and compensatory plans or arrangements.

Table of Contents

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 22, 2011	By:	/s/ TERRY W. RATHERT Terry W. Rathert Executive Vice President and Chief Financial Officer (Principal Financial Officer)

Table of Contents

Exhibit Index

Exhibit Number	Description
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield's Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield's Registration Statement on Form S-3 (Registration No. 333-32582))
3.1.2	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 12, 2004 (incorporated by reference to Exhibit 4.2.3 to Newfield's Registration Statement on Form S-8 (Registration No. 333-116191))
3.1.3	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield's Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
3.2	Amended and Restated Bylaws of Newfield (incorporated by reference to Exhibit 3.2 to Newfield's Current Report on Form 8-K filed with the SEC on February 6, 2009 (File No. 1-12534))
*10.1	Credit Agreement, dated as of June 2, 2011, by and among Newfield Exploration Company and JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, and BBVA Compass, The Bank of Tokyo-Mitsubishi UFJ, Ltd., and DNB Nor Bank ASA, as Co-Documentation Agents, and other Lenders thereto
†10.2	Newfield Exploration Company 2011 Omnibus Stock Plan (incorporated by reference to Exhibit 99.1 to Newfield's Registration Statement on Form S-8 (Reg. No. 333-173964) filed with the SEC on May 5, 2011)
†*10.3	Form of Executive Officer Restricted Stock Unit Award Agreement under 2011 Omnibus Stock Plan
†*10.4	Form of Executive Officer TSR Restricted Stock Unit Award Agreement under 2011 Omnibus Stock Plan
†*10.5	Form of Independent Director Restricted Stock Award Agreement under 2011 Omnibus Stock Plan
*31.1	Certification of Chief Executive Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

**101.INS	XBRL Instance Document
**101.SCH	XBRL Schema Document
**101.CAL	XBRL Calculation Linkbase Document
**101.LAB	XBRL Label Linkbase Document
**101.PRE	XBRL Presentation Linkbase Document
**101.DEF	XBRL Definition Linkbase Document

* Filed or furnished herewith.
** Furnished herewith.
† Identifies management contracts and compensatory plans or arrangements.