NEWFIELD EXPLORATION CO /DE/
Form 10-Q
July 26, 2013

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, 2013

OR

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

For the Transition Period from to .

Commission File Number: 1-12534

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

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

4 Waterway Square Place
Suite 100
The Woodlands, Texas 77380
(Address and Zip Code of principal executive offices)

(281) 210-5100
(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 ¨

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 ¨

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 ¨	Non-accelerated filer ¨	Smaller reporting company ¨

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No þ

As of July 22, 2013, there were 135,686,016 shares of the registrant's common stock, par value $0.01 per share, outstanding.

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

	June 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$51	$88
Accounts receivable	476	452
Inventories	106	132
Derivative assets	65	125
Other current assets	61	69
Total current assets	759	866
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,599 and $1,485 were excluded from amortization at June 30, 2013 and December 31, 2012, respectively)	15,297	14,346
Less — accumulated depreciation, depletion and amortization	(7,878)	(7,444)
Total property and equipment, net	7,419	6,902
Derivative assets	60	17
Long-term investments	62	58
Deferred taxes	37	24
Other assets	44	45
Total assets	$8,381	$7,912
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$57	$69
Accrued liabilities	849	801
Advances from joint owners	36	31
Asset retirement obligations	7	10
Derivative liabilities	6	6
Deferred taxes	21	42
Total current liabilities	976	959
Other liabilities	42	47
Derivative liabilities	—	15
Long-term debt	3,276	3,045
Asset retirement obligations	140	132
Deferred taxes	1,040	934
Total long-term liabilities	4,498	4,173
Commitments and contingencies (Note 13)	—	—
Stockholders' equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)	—	—
	1	1

Common stock ($0.01 par value, 200,000,000 shares authorized at June 30, 2013 and December 31, 2012; 136,668,275 and 136,530,907 shares issued at June 30, 2013 and December 31, 2012, respectively)		
Additional paid-in capital	1,536	1,522
Treasury stock (at cost, 991,707 and 1,216,591 shares at June 30, 2013 and December 31, 2012, respectively)	(29)	(36)
Accumulated other comprehensive loss	(4)	(7)
Retained earnings	1,403	1,300
Total stockholders' equity	2,907	2,780
Total liabilities and stockholders' equity	$8,381	$7,912

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Oil, gas and NGL revenues	$435	$350	$805	$753
Operating expenses:				
Lease operating	107	103	195	205
Production and other taxes	21	15	33	36
Depreciation, depletion and amortization	164	172	311	338
General and administrative	54	59	99	104
Total operating expenses	346	349	638	683
Income from operations	89	1	167	70
Other income (expense):				
Interest expense	(50)	(49)	(101)	(100)
Capitalized interest	13	18	27	36
Commodity derivative income (expense)	117	135	33	159
Other	2	(4)	4	(2)
Total other income (expense)	82	100	(37)	93
Income from continuing operations before income taxes	171	101	130	163
Income tax provision (benefit):				
Current	—	—	—	5
Deferred	65	37	49	55
Total income tax provision (benefit)	65	37	49	60
Income from continuing operations	106	64	81	103
Income from discontinued operations, net of tax	5	71	22	148
Net income	$111	$135	$103	$251
Earnings per share:				
Basic:				
Income from continuing operations	$0.78	$0.47	$0.60	$0.76
Income from discontinued operations	0.04	0.53	0.16	1.10
Basic earnings per share	$0.82	$1.00	$0.76	$1.86
Diluted:				
Income from continuing operations	$0.78	$0.47	$0.60	$0.76
Income from discontinued operations	0.04	0.53	0.16	1.09
Diluted earnings per share	$0.82	$1.00	$0.76	$1.85
Weighted-average number of shares outstanding for basic earnings per share	135	134	135	134
	136	135	136	135

Weighted-average number of shares outstanding for diluted earnings per share

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

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$111	$135	$103	$251
Other comprehensive income:				
Unrealized gain on investments, net of tax	1	—	3	2
Other comprehensive income, net of tax	1	—	3	2
Comprehensive income	$112	$135	$106	$253

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

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

	Six Months Ended June 30,	
	2013	2012
Cash flows from operating activities:		
Net income	$103	$251
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	439	465
Deferred tax provision (benefit)	68	54
Stock-based compensation	17	17
Commodity derivative (income) expense	(33)	(159)
Cash receipts on derivative settlements, net	35	86
Other non-cash charges	4	3
Changes in operating assets and liabilities:		
(Increase) decrease in accounts receivable	(14)	(5)
(Increase) decrease in inventories	20	(12)
(Increase) decrease in other current assets	8	(20)
(Increase) decrease in other assets	2	(1)
(Increase) decrease in accounts payable and accrued liabilities	(40)	(76)
Increase (decrease) in advances from joint owners	5	(26)
(Increase) decrease in other liabilities	(4)	(2)
Net cash provided by operating activities	610	575
Cash flows from investing activities:		
Additions to oil and gas properties	(876)	(875)
Acquisitions of oil and gas properties	(3)	(9)
Proceeds from sales of oil and gas properties	19	329
Additions to other property and equipment	(14)	(13)
Redemption of investments	1	—
Net cash used in investing activities	(873)	(568)
Cash flows from financing activities:		
Proceeds from borrowings under credit arrangements	1,425	1,663
Repayments of borrowings under credit arrangements	(1,194)	(1,749)
Proceeds from issuance of senior notes	—	1,000
Debt issue costs	(4)	(10)
Repayment of senior subordinated notes	—	(325)
Proceeds from issuances of common stock	1	—
Purchases of treasury stock, net	(2)	(6)
Net cash provided by financing activities	226	573
Increase (decrease) in cash and cash equivalents	(37)	580
Cash and cash equivalents, beginning of period	88	76
Cash and cash equivalents, end of period	$51	$656

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

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

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance, December 31, 2012	136.5	$1	(1.2)	$(36)	$1,522	$1,300	$ (7)	$2,780
Issuances of common stock	0.2	—			1			1
Stock-based compensation					22			22
Treasury stock, net			0.2	7	(9)			(2)
Net income						103		103
Other comprehensive income, net of tax							3	3
Balance, June 30, 2013	136.7	$1	(1.0)	$(29)	$1,536	$1,403	$ (4)	$2,907

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

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids (NGLs). Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast. Internationally, we focus on offshore oil developments in Malaysia and China.

Our consolidated financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and natural 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,” “our” or the “Company” 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 fairly state 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 consolidated 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, 2012.

Discontinued Operations

Following our decision to evaluate strategic alternatives for our businesses in Malaysia and China and the resulting assets-held-for-sale classification in the second quarter of 2013, the results of our international operations are reflected separately as discontinued operations in the consolidated statement of operations on a line immediately after “Income from continuing operations.” See Note 3, “Discontinued Operations,” for additional disclosures. These financial statements and notes are inclusive of our international operations unless otherwise noted.

Dependence on Commodity Prices

As an independent oil and natural gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil, natural gas and NGLs. Historically, the energy markets have been very volatile, and there can be no assurance that commodity prices will not be subject to wide fluctuations in the future. A substantial or extended decline in commodity 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, natural gas and NGL 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 quantities and values of proved oil, natural gas and NGL reserves used in calculating depletion and assessing impairment of our oil and gas properties. Actual results could differ significantly from these estimates. Our most significant financial estimates are associated with our estimated proved oil, natural gas and NGL reserves and the fair value of our derivative positions.

Investments

Investments consist 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 within the consolidated statement of comprehensive income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

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 $0.7 million and $0.3 million for each of the three-month periods ended June 30, 2013 and 2012, respectively, and approximately $2 million and $1 million for each of the six-month periods ended June 30, 2013 and 2012, respectively.

Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and natural gas operations and oil produced but not sold in our offshore operations in Malaysia and China. See Note 3, "Discontinued Operations" for details on our international crude oil inventory. Tubular goods and well equipment inventories are carried at the lower of cost or market.

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 $37 million and $27 million of internal costs during the three-month periods ended June 30, 2013 and 2012, respectively, and $73 million and $58 million during the six-month periods ended June 30, 2013 and 2012, respectively. Interest expense related to unproved properties also is capitalized into oil and gas properties.

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.

Capitalized costs and estimated future development costs are amortized using 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, natural gas and NGL reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior 12 months, adjusted for market differentials (SEC pricing), applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus
- the cost of properties not included in the costs being amortized, if any; less
- related income tax effects.

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, natural gas and NGL prices decrease significantly for a prolonged period of time or if we have substantial downward revisions in our estimated proved reserves. At June 30, 2013, the ceiling value of our reserves was calculated based upon SEC pricing of $3.44 per MMBtu for natural gas and $91.53 per barrel of oil. Using these prices, the cost center ceiling with respect to our domestic full cost pool exceeded the net capitalized costs of the respective cost centers. As such, no ceiling test writedown was required at June 30, 2013. If there are further declines in SEC pricing of oil and natural gas subsequent to June 30, 2013, we may be required to record a ceiling test writedown in future periods.

At December 31, 2012, the ceiling value of our reserves was calculated based upon SEC pricing of $2.76 per MMBtu for natural gas and $94.84 per barrel of oil. Using these prices, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by, and caused a writedown of, approximately $1.5 billion ($948 million, after-tax).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Other Property and Equipment

Furniture, fixtures and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives, which range from three to seven years. Gathering systems and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives of 25 years.

Segment Reporting

Our continuing operations are comprised of a single business segment, the domestic exploration, development and production of oil and natural gas. Prior to classifying our international businesses as held-for-sale and discontinued operations, we reported business segments for Malaysia and China.

Accounting for Asset Retirement Obligations

The change in our asset retirement obligation (ARO) is set forth below (in millions):

Balance at January 1, 2013	$142
Accretion expense	5
Additions	4
Revisions	2
Settlements	(6)
Balance at June 30, 2013	147
Less: Current portion of ARO at June 30, 2013	(7)
Total long-term ARO at June 30, 2013	$140

Derivative Financial Instruments

Our derivative financial instruments are recorded on the consolidated balance sheet at fair value with changes in the derivative's fair value recognized in current earnings. 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.

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

Offsetting Assets and Liabilities

Our derivative financial instruments are subject to master netting arrangements and are reflected on our consolidated balance sheet accordingly. See Note 5, "Derivative Financial Instruments," for details regarding the gross amounts, as well as the impact of our netting arrangements on our net derivative position. We have only offset assets and liabilities in relation to our derivative financial instruments. We do not have any gross amounts that are subject to a master netting arrangement that are not offset in our consolidated balance sheet.

New Accounting Requirements

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance requires disclosure of both gross and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. We adopted the guidance in the quarter ended March 31, 2013. Adoption of the additional disclosures regarding offsetting assets and liabilities did not have a material impact on our financial position or results of operations.

In February 2013, the FASB issued guidance regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The guidance is effective for interim and annual periods beginning after December 15, 2012. We

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(Unaudited)

adopted the guidance in the quarter ended March 31, 2013. Adoption of the new reporting guidance did not have a material impact on our financial position or results of operations as we did not have reclassifications during the periods presented.

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 (excluding unvested restricted stock and restricted stock units) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted stock and restricted stock units (using the treasury stock method). Under the treasury stock method, the amount the employee must pay for exercising stock options, the amount of unrecognized compensation expense related to unvested stock-based compensation grants and the amount of excess tax benefits that would be recorded when the award becomes deductible are assumed to be used to repurchase shares. See Note 11, “Stock-Based Compensation.”

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions, except per share data)			
Income (numerator):				
Income from continuing operations	$106	$64	$81	$103
Income from discontinued operations, net of tax	5	71	22	148
Net income — basic and diluted	$111	$135	$103	$251
Weighted-average shares (denominator):				
Weighted-average shares — basic	135	134	135	134
Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period[(1)]	1	1	1	1
Weighted-average shares — diluted	136	135	136	135
Earnings per share:				
Basic:				
Income from continuing operations	$0.78	$0.47	$0.60	$0.76
Income from discontinued operations	0.04	0.53	0.16	1.10
Basic earnings per share	$0.82	$1.00	$0.76	$1.86
Diluted:				
Income from continuing operations	$0.78	$0.47	$0.60	$0.76
Income from discontinued operations	0.04	0.53	0.16	1.09
Diluted earnings per share	$0.82	$1.00	$0.76	$1.85

(1)

Excludes 3.4 million and 3.7 million shares of unvested restricted stock or restricted stock units and stock options for the three- and six-month periods ended June 30, 2013, respectively, and 3.0 million shares for the three- and six-month periods ended June 30, 2012 because including the effect would have been anti-dilutive.

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

3. Discontinued Operations:

In February 2013, we announced our decision to explore strategic alternatives for our international businesses. In accordance with specific accounting requirements, we did not meet the criteria to classify our international businesses as held-for-sale until the second quarter of 2013. As a result, our Malaysia and China operations are classified as discontinued operations at June 30, 2013, and the historical results of operations for our international operations are reflected in our financial statements as “discontinued operations.”
The following table summarizes the financial results of our discontinued operations for the following periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Oil and gas revenues	$188	$277	$470	$552
Operating expenses	159	166	373	314
Income from discontinued operations	29	111	97	238
Other income (expense)	(1)	2	(1)	—
Income from discontinued operations before income taxes	28	113	96	238
Income tax provision (benefit):				
Current	6	47	55	91
Deferred	17	(5)	19	(1)
Total income tax provision	23	42	74	90
Income from discontinued operations, net of tax	$5	$71	$22	$148

Income Taxes

The effective tax rates for our discontinued operations for the three months ended June 30, 2013 and 2012 were 81.1% and 37.3%, respectively. The effective tax rates for the six months ended June 30, 2013 and 2012 were 76.7% and 37.7%, respectively. Historically, our international effective tax rate was approximately 37%. However, the effective tax rates for the three and six months ended June 30, 2013 were affected by our fourth quarter 2012 decision to repatriate earnings from our foreign operations.

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

A summary of assets and liabilities included in our consolidated balance sheet attributable to discontinued operations follows:

	June 30, 2013	December 31, 2012
	(In millions)	
Current assets:		
Cash and cash equivalents	$42	$76
Accounts receivable	231	207
Inventories	72	91
Other current assets	37	31
Total current assets	382	405
Noncurrent assets:		
Oil and gas properties, net of accumulated depreciation, depletion and amortization of $964 and $843 as of June 30, 2013 and December 31, 2012, respectively	850	781
Deferred taxes	37	24
Other assets	4	4
Total noncurrent assets	891	809
Total assets	$1,273	$1,214
Current liabilities:		
Accounts payable	$54	$50
Accrued liabilities	299	269
Other current liabilities	21	21
Total current liabilities	374	340
Noncurrent liabilities:		
Asset retirement obligations	39	38
Deferred taxes	75	41
Other liabilities	17	23
Total noncurrent liabilities	131	102
Total liabilities	$505	$442

Crude Oil Inventories

Substantially all of the crude oil from our offshore operations in Malaysia and China is produced into floating production, storage and off-loading vessels (FPSOs) or onshore storage terminals and “lifted” and sold periodically as barge quantities are accumulated. The product inventory from our international operations consisted of approximately 508,000 barrels and 744,000 barrels of crude oil valued at cost of $41 million and $64 million at June 30, 2013 and December 31, 2012, respectively, and are included in the "Inventories" line item in the preceding table and our consolidated balance sheet. 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 activities. At June 30, 2013, the oil and gas properties associated with our discontinued operations included $116 million not subject to amortization, comprised of $45 million incurred prior to 2011, $6 million incurred in 2011, $24 million incurred in 2012 and $41 million incurred in 2013. The cost center ceilings with respect to our Malaysia and China full cost pools exceeded the net capitalized costs of the respective cost centers at December 31, 2012 and June 30, 2013, and as such, no ceiling test writedowns were required.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

4. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following:

	June 30, 2013	December 31, 2012
	(In millions)	
Oil and gas properties:		
Subject to amortization	$13,466	$12,647
Not subject to amortization	1,599	1,485
Gross oil and gas properties	15,065	14,132
Accumulated depreciation, depletion and amortization	(7,800)	(7,378)
Net oil and gas properties	7,265	6,754
Other property and equipment:		
Furniture, fixtures and equipment	145	141
Gathering systems and equipment	87	73
Accumulated depreciation and amortization	(78)	(66)
Net other property and equipment	154	148
Total property and equipment, net	$7,419	$6,902

The following is a summary of our oil and gas properties not subject to amortization as of June 30, 2013. 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, the entire evaluation can take significantly longer than four years. At June 30, 2013, approximately 88% of our oil and gas properties not subject to amortization were associated with unconventional resource plays.

	Costs Incurred In				
	2013	2012	2011	2010 and Prior	Total
	(In millions)				
Acquisition costs	$37	$114	$264	$381	$796
Exploration costs	418	70	18	36	542
Development costs	—	31	39	—	70
Fee mineral interests	—	—	—	23	23
Capitalized interest	27	67	74	—	168
Total oil and gas properties not subject to amortization	$482	$282	$395	$440	$1,599

Gulf of Mexico Asset Sale

In October 2012, we closed on the sale of our remaining assets in the Gulf of Mexico to W&T Offshore, Inc. for approximately $208 million, subject to customary post-closing adjustments. The sale of our remaining assets in the Gulf of Mexico did not significantly alter the relationship between capitalized costs and proved reserves and as such, all proceeds were recorded as adjustments to our domestic full cost pool with no gain or loss recognized. These consolidated financial statements include the results of our Gulf of Mexico operations through the date of sale.

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Other Asset Sales

During the six months ended June 30, 2013 and the year ended December 31, 2012, we sold certain oil and gas properties for proceeds of approximately $19 million and $630 million (includes Gulf of Mexico asset sale discussed above), respectively. The cash flows and results of operations for the assets included in a sale are included in our consolidated financial statements up to the date of sale. All of the proceeds associated with our asset sales were recorded as adjustments to our domestic full cost pool.

5. Derivative Financial Instruments:

Commodity Derivative Instruments

We utilize the following derivative strategies, which consist of either a single derivative instrument or a combination of instruments, to hedge against the variability in cash flows associated with the forecasted sale of our future oil and natural gas production domestically:

- fixed-price swaps (swap). With respect to a swap position, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap strike 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 strike price;
- collars (combination of purchased put options (floor) and sold call options (ceiling)). For a collar position, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor strike price while we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling strike price. 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 strike price and equal to or less than the ceiling strike price;
- fixed-price swaps with sold puts. A swap with a sold put position consists of a standard swap position plus a put sold by us with a strike price below the associated fixed-price swap. This structure enables us to increase the fixed-price swap with the value received through the sale of the put. If the settlement price for any settlement period falls equal to or below the put strike price, then we will only receive the difference between the swap price and the put strike price. If the settlement price is greater than the put strike price, the result is the same as it would have been with a standard swap only; and
- collars with sold puts. A collar with a sold put position consists of a standard collar position plus a put sold by us with a strike price below the floor strike price of the collar. This structure enables us to improve the collar strike prices with the value received through the sale of the additional put. If the settlement price for any settlement period falls equal to or below the additional put strike price, then we will receive the difference between the floor strike price and the additional put strike price. If the settlement price is greater than the additional put strike price, the result is the same as it would have been with a standard collar only.

While the use of these derivative instruments limits the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements.

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, estimated volatility, non-performance risk adjustments using credit default swaps and, in the case of collars and sold puts, the remaining term of options. The calculation of the fair value of

collars and sold puts requires the use of an option-pricing model. See Note 8, “Fair Value Measurements.”

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At June 30, 2013, we had outstanding positions with respect to our future production as set forth in the tables below.

Natural Gas

Period and Type of Instrument	Volume in MMMBtus	NYMEX Contract Price Per MMBtu				Estimated Fair Value Asset (Liability) (In millions)
		Swaps (Weighted Average)	Sold Puts (Weighted Average)	Collars Floors (Weighted Average)	Ceilings (Weighted Average)	
2013:						
Fixed-price swaps	27,600	$4.08	—	—	—	$12
Collars with sold puts[(A)]	17,810	3.45	$3.98	$5.36	$6.30	19
Collars with sold puts	4,575	—	3.00	3.75	4.75	1
2014:						
Fixed-price swaps	85,775	3.98	—	—	—	6
Collars	23,725	—	—	3.75	4.62	3
2015:						
Fixed-price swaps	49,275	4.28	—	—	—	7
Collars	38,325	—	—	3.93	4.74	4
Total						$52

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(A) During the first quarter of 2012, natural gas spot market prices were below the puts we sold on our collar with sold put positions for April through December 2012 and the full-year 2013, exposing us further to the softening natural gas spot market. As a result, during the first quarter of 2012, we entered into additional swap positions in the over-the-counter market that effectively prevented any further erosion in the value of our natural gas collar with sold put positions. The new swap positions added during the first quarter of 2012 were for the same volumes as our full-year 2013 collar with sold put positions. The economics from the combination of these additional swap positions and our natural gas collar with sold put positions will result in an effective average fixed price of $4.83 per MMBtu as long as natural gas spot prices for the respective time periods settle below the puts we sold on our collar with sold put positions. In the event natural gas spot prices settle above the ceilings on our associated collar with sold put positions, we would not recover the difference through the sale of our production as we would realize losses on both instruments discussed above.

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Crude Oil

Period and Type of Instrument	Volume in MBbls	NYMEX Contract Price Per Bbl				Estimated Fair Value Asset (Liability) (In millions)
		Swaps (Weighted Average)	Sold Puts (Weighted Average)	Collars Floors (Weighted Average)	Ceilings (Weighted Average)	
2013:						
Fixed-price swaps	489	$89.67	—	—	—	$(3)
Fixed-price swaps with sold puts	1,840	97.49	$75.00	—	—	5
Collars with sold puts	4,815	—	80.00	$95.00	$115.20	15
2014:						
Fixed-price swaps	5,757	89.74	—	—	—	—
Fixed-price swaps with sold puts	4,745	95.00	75.00	—	—	16
Collars with sold puts	2,190	—	75.83	90.83	102.93	4
2015:						
Fixed-price swaps	6,567	90.39	—	—	—	30
Total						$67

Additional Disclosures about Derivative Instruments and Hedging Activities

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

	Derivative Assets				Derivative Liabilities			
	Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location		Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location	
			Current	Noncurrent			Current	Noncurrent
June 30, 2013	(In millions)				(In millions)			
Natural gas positions	$62	$(7)	$42	$13	$(10)	$7	$(3)	$—
Oil positions	83	(13)	23	47	(16)	13	(3)	—
Total	$145	$(20)	$65	$60	$(26)	$20	$(6)	$—
December 31, 2012								
Natural gas positions	$86	$(5)	$79	$2	$(16)	$5	$(4)	$(7)
Oil positions	77	(16)	46	15	(26)	16	(2)	(8)
Total	$163	$(21)	$125	$17	$(42)	$21	$(6)	$(15)

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The amount of gain (loss) recognized in "Commodity derivative income (expense)" in our consolidated statement of operations related to our derivative financial instruments was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Derivatives not designated as hedging instruments:				
Realized gain (loss) on natural gas positions	$5	$54	$32	$98
Realized gain (loss) on oil positions	3	—	3	(7)
Realized gain (loss) on basis positions	—	(2)	—	(5)
Total realized gain (loss)	8	52	35	86
Unrealized gain (loss) on natural gas positions	70	(88)	(18)	(83)
Unrealized gain (loss) on oil positions	39	169	16	151
Unrealized gain (loss) on basis positions	—	2	—	5
Total unrealized gain (loss)	109	83	(2)	73
Total	$117	$135	$33	$159

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, 2013, eight of our 15 counterparties accounted for approximately 85% of our estimated future hedged production, with no single counterparty accounting for more than 17% of that production.

A portion of our derivative instruments are with lenders under our credit facility. Our credit facility, senior notes, 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:

Accounts receivable consisted of the following:

	June 30, 2013	December 31, 2012
	(In millions)	
Revenue	$293	$291
Joint interest	173	154
Other	11	8
Reserve for doubtful accounts	(1)	(1)
Total accounts receivable	$476	$452

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7. Accrued Liabilities:

Accrued liabilities consisted of the following:

	June 30, 2013	December 31, 2012
	(In millions)	
Revenue payable	$124	$95
Accrued capital costs	425	355
Accrued lease operating expenses	83	95
Employee incentive expense	26	50
Accrued interest on debt	43	43
Taxes payable	107	108
Other	41	55
Total accrued liabilities	$849	$801

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 fixed-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 commodity options (price collars and sold puts) and other financial investments. Although we utilize third-party broker quotes to assess the reasonableness of our prices and valuation techniques for derivative instruments, we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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Fair Value of Investments and Derivative Instruments

The following table summarizes the valuation of our financial assets (liabilities) of our continuing operations by measurement 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, 2012:				
Money market fund investments	$22	$—	$—	$22
Deferred compensation plan assets	6	—	—	6
Investments available-for-sale:				
Equity securities	7	—	—	7
Auction rate securities	—	—	36	36
Oil and gas derivative swap contracts	—	6	—	6
Oil and gas derivative option contracts	—	—	115	115
Total	$35	$6	$151	$192
As of June 30, 2013:				
Money market fund investments	$1	$—	$—	$1
Deferred compensation plan assets	7	—	—	7
Investments available-for-sale:				
Equity securities	8	—	—	8
Auction rate securities	—	—	39	39
Oil and gas derivative swap contracts	—	77	—	77
Oil and gas derivative option contracts	—	—	42	42
Total	$16	$77	$81	$174

The determination of the fair values above incorporates various factors, which include the impact of our non-performance risk on our liabilities, the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), if any. 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, 2013, we held $39 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 since the time of purchase of $6 million ($4 million net of tax) recorded under the caption “Accumulated other comprehensive loss” on our consolidated balance sheet. As of December 31, 2012, we held $36 million of auction rate securities, which reflected a decrease in the fair value of $9 million ($6 million net of tax) since the date of purchase. 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.

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

	Investments	Derivatives	Total
	(In millions)		
Balance at January 1, 2012	$32	$71	$103
Total realized or unrealized gains (losses):			
Included in earnings	—	157	157
Included in other comprehensive income (loss)	2	—	2
Purchases, issuances and settlements:			
Settlements	—	(43)	(43)
Transfers in and out of Level 3	—	—	—
Balance at June 30, 2012	$34	$185	$219
Change in unrealized gains or losses included in earnings relating to investments and derivatives still held at June 30, 2012	$—	$141	$141
Balance at January 1, 2013	$36	$115	$151
Total realized or unrealized gains (losses):			
Included in earnings	—	(41)	(41)
Included in other comprehensive income (loss)	4	—	4
Purchases, issuances and settlements:			
Settlements	(1)	(32)	(33)
Transfers in and out of Level 3	—	—	—
Balance at June 30, 2013	$39	$42	$81
Change in unrealized gains or losses included in earnings relating to investments and derivatives still held at June 30, 2013	$—	$5	$5

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Derivatives. Our valuation models for level 3 derivative contracts are primarily industry-standard models that consider various factors, including certain significant unobservable inputs such as (a) quoted forward prices for commodities, (b) volatility factors and (c) counterparty credit risk. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the strike prices fixed by the hedge agreements, and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. Significant increases (decreases) in the quoted forward prices for commodities generally lead to corresponding decreases (increases) in the fair value measurement of our oil and gas derivative contracts. Significant changes in the volatility factors utilized in our option-pricing model can cause significant changes in the fair value measurement of our oil and gas derivative contracts.

The determination of the fair values of derivative instruments incorporates various factors that 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). Historically, we have not experienced significant changes in the fair value of our derivative contracts resulting from changes in counterparty credit risk as the counterparties for all of our hedging transactions have an “investment grade” credit rating.

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Investments. We utilize a discounted cash flow model in the determination of the valuation of our auction rate securities classified as Level 3. This model considers various inputs including (a) the coupon rate specified under the debt instrument, (b) the current credit rating of the underlying issuers, (c) collateral characteristics and (d) risk-adjusted discount rates. The most significant unobservable factor in determining the fair value of these investments, is market liquidity. A significant change in the liquidity of the market for auction rate securities would lead to a corresponding change in the fair value measurement of these investments.

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

	Estimated Fair Value	Quantitative Information about Level 3 Fair Value Measurements						
Instrument Type	Asset (Liability) (In millions)	Valuation Technique	Unobservable Input	Range				
Oil option contracts	$12	Option model	NYMEX oil price forward curve	$88.22		—	$96.56	
			Oil price volatility curves	17.34	%	—	27.51	%
			Credit risk	0.01	%	—	1.33	%
Natural gas option contracts	$30	Option model	NYMEX natural gas price forward curve	$3.56		—	$4.38	
			Natural gas price volatility curves	19.52	%	—	35.09	%
			Credit risk	0.01	%	—	2.48	%

The underlying inputs in the determination of the valuation of our auction rate securities are developed by a third party and, therefore, not included in the quantitative analysis above.

Fair Value of Debt

The estimated fair value of our notes, based on quoted prices in active markets (Level 1) as of the indicated dates, was as follows:

	June 30, 2013	December 31, 2012
	(In millions)	
5¾% Senior Notes due 2022	$746	$836
5 % Senior Notes due 2024	979	1,074
7 % Senior Subordinated Notes due 2018	624	630
6 % Senior Subordinated Notes due 2020	728	749

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9. Debt:

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

	June 30, 2013	December 31, 2012
	(In millions)	
Senior unsecured debt:		
Revolving credit facility - LIBOR based loans	$140	$—
Money market lines of credit [1]	91	—
Total credit arrangements	231	—
5¾% Senior Notes due 2022	750	750
5 % Senior Notes due 2024	1,000	1,000
Total senior unsecured debt	1,981	1,750
7 % Senior Subordinated Notes due 2018	600	600
6 % Senior Subordinated Notes due 2020	700	700
Discount on notes	(5)	(5)
Total long-term debt	$3,276	$3,045

(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 April 2013, we entered into the second amendment to the credit facility, which allows the sale of the Company's international subsidiaries pursuant to certain terms and conditions. In June 2013, we entered into the third amendment of our Credit Agreement. This amendment extended the maturity date of the revolving credit facility from June 2016 to June 2018 and increased the borrowing capacity from $1.25 billion to $1.4 billion. We incurred $4 million of deferred financing costs related to this amendment. As of June 30, 2013, the largest individual loan commitment by any lender was 14% of total commitments.

Loans under the credit facility bear interest, at our option, equal to (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank, N.A. 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, 2013) 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, 2013).

Under our 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, 2013). We incurred aggregate commitment fees under our current credit facility of approximately $0.7 million and $1.7 million for the three and six months ended June 30, 2013, respectively, which are recorded in “Interest expense” on our consolidated statement of operations. For the three and six months ended June 30, 2012, we incurred commitment fees under our current credit facility of approximately $0.6 million and $1.6 million, respectively.

Our credit facility has restrictive financial 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, 2013, we were in compliance with all of our debt covenants.

As of June 30, 2013, we had $70 million of undrawn letters of credit outstanding under our credit facility. 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, 2013). Additionally, as of June 30, 2013, we had $2 million of other undrawn letters of credit outstanding.

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Subject to compliance with the restrictive covenants in our credit facility, at June 30, 2013, we also had a total of $104 million of available borrowing capacity under our money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

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 notes and 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 notes, 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 continuing operations 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,	
	2013	2012	2013	2012
	(In millions)			
Amount computed using the statutory rate	$60	$35	$46	$57
Increase (decrease) in taxes resulting from:				
State and local income taxes, net of federal effect	5	2	3	3
Total provision (benefit) for income taxes	$65	$37	$49	$60

The effective tax rates for continuing operations for the three months ended June 30, 2013 and 2012 were 38.1% and 37.0%, respectively. The effective tax rates for the six months ended June 30, 2013 and 2012 were 37.9% and 37.1%, respectively.

As of June 30, 2013, we did not have a liability for uncertain tax positions, and as such, we had not accrued related interest or penalties. The tax years 2009 through 2012 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

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11. Stock-Based Compensation:

All stock-based compensation equity awards to employees and non-employee directors are currently granted under the 2011 Omnibus Stock Plan. 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 both February 2011 and February 2013, we also granted cash-settled restricted stock units to a limited number of employees. These awards 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 dates indicated, our stock-based compensation consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Total stock-based compensation	$12	$12	$24	$24
Capitalized in oil and gas properties	(4)	(3)	(7)	(7)
Net stock-based compensation expense	$8	$9	$17	$17

As of June 30, 2013, we had approximately $102 million of total unrecognized stock-based compensation expense related to unvested stock-based compensation awards. This compensation expense is expected to be recognized on a straight-line basis over the applicable remaining vesting periods. The full amount is expected to be recognized within four years.

Stock Options. The following table provides information about stock option activity:

	Number of Shares Underlying Options	Weighted-Average Exercise Price per Share	Weighted-Average Grant Date Fair Value per Share	Weighted-Average Remaining Contractual Life	Aggregate Intrinsic Value[1]
	(In thousands)			(In years)	(In millions)
Outstanding at December 31, 2012	901	$38.06		3.3	$1
Granted	—	—	$—		
Exercised	(39)	17.85			1
Forfeited	(73)	37.12			
Outstanding at June 30, 2013	789	$39.15		3.0	$—
Exercisable at June 30, 2013	789	$39.15		3.0	$—

(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, 2013, the last reported sales price of our common stock on the New York Stock Exchange was $23.89 per share.

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Restricted Stock. The following table provides information about restricted stock and restricted stock unit activity:

	Service-Based Shares	Performance/ Market-Based Shares	Total Shares	Weighted-Average Grant Date Fair Value per Share
	(In thousands, except per share data)			
Non-vested shares outstanding at December 31, 2012	2,371	438	2,809	$43.31
Granted	1,541	300	1,841	28.14
Forfeited	(338)	(14)	(352)	39.31
Vested	(528)	—	(528)	41.13
Non-vested shares outstanding at June 30, 2013	3,046	724	3,770	$36.58

Cash-Settled Restricted Stock Units. During both the first quarter of 2011 and 2013, we granted cash-settled restricted stock units to a limited number of employees that vest over three years. The value of the awards, and the associated stock-based compensation expense, is based on the Company’s stock price. In February 2012, the first tranche of the 2011 grants vested, which required settlement of approximately 44,000 cash-settled restricted stock units for approximately $1.7 million. In February 2013, the second tranche of the 2011 grants vested, which required settlement of approximately 38,000 cash-settled restricted stock units for approximately $1.1 million. As of June 30, 2013, we had approximately 234,000 cash-settled restricted stock units outstanding and unrecognized stock-based compensation expense of approximately $3.2 million for cash-settled restricted stock units.

Employee Stock Purchase Plan. During the first six months of 2013, options to purchase approximately 99,000 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $6.90 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 0.11%, an expected life of six months and weighted-average volatility of 40%.

12. Voluntary Severance Program:

During the second quarter of 2013, we completed a voluntary severance program in order to lower cash operating costs and change the structure of our organization to better align with our focus on domestic resource plays. The estimated total expense of the voluntary severance program was approximately $8 million, all of which has been recognized in "General and administrative" expense in our consolidated statement of operations.

13. 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 (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) 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 positions, cash flows or results of operations.

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

14. Supplemental Cash Flows Information:

The following table presents information about supplemental cash flows for the following periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Non-cash items excluded from the statement of cash flows:				
(Increase) decrease in accrued capital expenditures	$(62)	$(23)	$(70)	$(66)
(Increase) decrease in asset retirement costs	2	(9)	(2)	(5)

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

Overview

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our principal domestic areas of operation include the Mid-Continent, the Rocky Mountains and the onshore Gulf Coast. Internationally, we focus on offshore oil developments in Malaysia and China.

In February 2013, we announced our decision to explore strategic alternatives for our international businesses in Malaysia and China. The decision to market our international businesses followed a comprehensive review of the Company's strategy in which we decided to focus on our liquids-rich domestic resource areas. In accordance with accounting requirements, we did not meet the criteria to classify our international businesses as held-for-sale and discontinued operations until the second quarter of 2013. As such, the results of operations for our international businesses are reflected as “discontinued operations” and discussed further in Note 3, "Discontinued Operations," to our consolidated financial statements appearing earlier in this report.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and locate or acquire new oil and natural gas reserves to replace those reserves being produced. Our revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable. Prices for oil, natural gas and NGLs fluctuate widely and affect:

- the amount of cash flows available for capital expenditures;
- our ability to borrow and raise additional capital; and
- the quantity of oil, natural gas and NGLs that we can economically produce.

We prepare our financial statements in conformity with generally accepted accounting principles in the United States of America, which require 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 natural gas reserves. In addition, we use the full cost method of accounting for our oil and gas 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 assets, are capitalized. The net capitalized costs for our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves. If these costs exceed the limit, we are required to charge the excess to earnings, also referred to as a “ceiling test writedown.” At December 31, 2012, the unamortized net capitalized costs of our domestic oil and gas properties exceeded the ceiling amount by, and caused a writedown of, approximately $1.5 billion ($948 million, after-tax). At June 30, 2013, using SEC pricing of $3.44 per MMBtu for natural gas and $91.53 per barrel of oil, adjusted for market differentials, the present value of our estimated future net cash flows from domestic proved reserves exceeded the net capitalized costs for our oil and gas properties. Therefore, we did not have a domestic ceiling test writedown as of June 30, 2013. No ceiling test writedowns were required for our oil and gas properties in Malaysia and China at December 31, 2012 or June 30, 2013. The risk of incurring a ceiling test writedown increases when commodity prices are low for a sustained period of time. If there are further declines in SEC pricing of oil and natural gas subsequent to June 30, 2013, we may be required to record a ceiling test writedown in future periods.

Results of Continuing Operations

Our continuing operations consist of our exploration, development and production activities in the United States.

Revenues. Our revenues are primarily from the sale of oil, natural gas and NGLs and do not include the effects of settlements of our derivative positions. 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 volume of production sold.

Revenues from continuing operations of $435 million for the second quarter of 2013 were 24% higher than the comparable period of 2012 primarily due to an increase in commodity prices and liquids production. Our crude oil production increased 13% in the second quarter of 2013 compared to the second quarter of 2012, which was partially offset by natural decline in gas production. Consistent with our continued focus on our higher margin liquids production, we limited our investment in natural gas production.

Revenues of $805 million for the first six months of 2013 were 7% higher than the comparable period of 2012; however, excluding the impact on production of the sale of our Gulf of Mexico assets in 2012, our revenues were 20% higher than the comparable period of 2012. More than half the increase was attributable to increases in NGL production in our Mid-Continent and onshore Gulf Coast regions of 256% and 39%, respectively, partially offset by decreased realized NGL prices. Additionally, oil production in the Mid-Continent, onshore Gulf Coast and Rocky Mountains regions increased 49%, 31% and 8%, respectively, during the six months ended June 30, 2013, but was partially offset by lower crude oil prices. While natural gas production declined, a 41% increase in the realized price during the period added revenues of approximately $14 million. The following table reflects our production from continuing operations and average realized commodity prices for the following periods:

	Three Months Ended June 30,		Percentage Increase (Decrease)	Six Months Ended June 30,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
Production:[1][2]						
Crude oil and condensate (MBbls)	3,399	3,014	13 %	6,364	6,032	5 %
Natural gas (Bcf)	29.7	37.8	(21)%	58.1	76.1	(24)%
NGLs (MBbls)	1,268	530	139 %	2,285	1,109	106 %
Total (MBOE)	9,617	9,835	(2)%	18,329	19,818	(8)%
Average Realized Prices:[2][3]						
Crude oil and condensate (per Bbl)	$83.66	$82.41	2 %	$83.78	$86.82	(4)%
Natural gas (per Mcf)	3.74	2.26	66 %	3.45	2.45	41 %
NGLs (per Bbl)	29.06	27.52	6 %	28.87	35.71	(19)%
Crude oil equivalent (per BOE)	45.28	35.62	27 %	43.94	38.00	16 %

(1) Represents volumes sold regardless of when produced. Excludes natural gas produced and consumed in operations of 2.2 Bcf and 1.8 Bcf during the three months ended June 30, 2013 and 2012, respectively, and 4.7 Bcf and 4.0 Bcf during the six months ended June 30, 2013 and 2012, respectively.

(2) Historically, we reported NGL volumes combined with crude oil and condensate production. In our Form 10-K for the period ended December 31, 2012, we began reporting NGL production separately from crude oil and condensate production. As such, all production volumes and average realized prices for the three and six months ended June 30, 2012 have been recalculated for comparability between periods.

(3) Had we included the effects of derivative contracts not designated for hedge accounting, the average realized price for total natural gas would have been $3.91 and $3.65 per Mcf for the three months ended June 30, 2013 and 2012, respectively; and $4.00 and $3.67 per Mcf for the six months ended June 30, 2013 and 2012, respectively. Our average crude oil realized price would have been $84.52 and $82.33 per Bbl for the three months ended June 30, 2013 and 2012, respectively, and $84.31 and $85.61 per Bbl for the six months ended June 30, 2013 and 2012, respectively. We did not have any derivative contracts associated with NGL production for the periods presented.

Production. Our second quarter 2013 total production from continuing operations decreased 218 MBOE, or 2% compared to second quarter 2012. Our remaining Gulf of Mexico assets, which were sold in the fourth quarter of 2012, contributed approximately 700 MBOE in the second quarter of 2012. Excluding the 2012 Gulf of Mexico volumes, period-over-period production increased approximately 450 MBOE across all our other domestic regions as a result of increased liquids production offset by decreased natural gas production. The decrease in natural gas production was due to natural decline as a result of reduced investment in natural gas wells. Excluding the effect of the sale of our Gulf of Mexico assets, our domestic liquids production increased approximately 42% in the second quarter of 2013, compared to the second quarter of 2012. NGL production comprised more than half of the increase in liquids production for the second quarter 2013.

For the six months ended June 30, 2013, total production from continuing operations decreased 8% compared to the same period of 2012. The entire decrease relates to the sale of our Gulf of Mexico assets during 2012. Excluding the impact on production of the sale of our Gulf of Mexico assets, total production remained relatively flat as compared to the same period of 2012. Although total production was relatively flat, liquids production increased 35% but was offset by decreases in natural gas production across our domestic regions. The decrease in natural gas production was due to natural decline as a result of reduced investment in natural gas wells. NGL production comprised approximately 60% of the increase in liquids production for the period.

Operating Expenses. The following tables present information about our operating expenses for our continuing operations for the following periods:

	Unit-of-Production Three Months Ended June 30,		Percentage Increase (Decrease)	Total Amount Three Months Ended June 30,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
	(Per BOE)			(In millions)		
Lease operating	$11.24	$10.57	6 %	$107	$103	4 %
Production and other taxes	2.20	1.54	43 %	21	15	39 %
Depreciation, depletion and amortization	16.97	17.44	(3)%	164	172	(5)%
General and administrative	5.60	6.01	(7)%	54	59	(9)%
Total operating expenses	$36.01	$35.56	1 %	$346	$349	(1)%

Our operating expenses for continuing operations for the three months ended June 30, 2013, stated on a per BOE basis, were up slightly over the same period of 2012. The primary offsetting components within our domestic operating expenses are as follows:

- Lease operating expense (LOE) includes normally recurring expenses to operate and produce our oil and natural gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. LOE increased primarily due to increased transportation and processing costs of $1.03 per BOE primarily due to increased NGL production, partially offset by decreases in non-recurring expenses of $0.53 per BOE primarily due to the sale of our Gulf of Mexico assets in 2012.
- Production and other taxes increased 39%, or $6 million, in comparison to the second quarter of 2012. Almost two-thirds of the increase was due to new wells coming online in 2013 in our Rocky Mountains region combined with higher average realized prices for crude oil. Approximately 25% of the increase was primarily due to production tax credits received during the second quarter of 2012 in our onshore Gulf Coast region, which resulted in lower than normal production tax expense for the second quarter of 2012.
- General and administrative (G&A) expense per BOE decreased 7%, primarily due to decreases in employee-related expenses, offset by $8 million in one-time charges related to our voluntary severance program. During the second quarter of 2013, we capitalized $25 million ($2.62 per BOE) of direct internal costs as compared to $24 million ($2.40 per BOE) during the second quarter of 2012.

	Unit-of-Production Six Months Ended June 30,		Percentage Increase (Decrease)	Total Amount Six Months Ended June 30,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
	(Per BOE)			(In millions)		
Lease operating	$10.67	$10.41	2 %	$195	$205	(5)%
Production and other taxes	1.81	1.81	— %	33	36	(8)%
Depreciation, depletion and amortization	16.94	17.04	(1)%	311	338	(8)%
General and administrative	5.40	5.24	3 %	99	104	(5)%
Total operating expenses	$34.82	$34.50	1 %	$638	$683	(7)%

Our operating expenses for continuing operations for the six months ended June 30, 2013, stated on a per BOE basis, were up slightly over the same period of 2012, with no meaningful period-over-period variances. However, after excluding the impact of the sale of our Gulf of Mexico assets in 2012, transportation and processing fees increased approximately 27%, primarily as a result of the 141% increase in NGL production across our domestic regions. Our

other operating expenses, on a per BOE basis, remained relatively comparable period over period.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Gross interest expense:				
Credit arrangements	$2	$3	$4	$5
Senior notes	25	12	50	23
Senior subordinated notes	23	34	47	72
Total gross interest expense	50	49	101	100
Capitalized interest	(13)	(18)	(27)	(36)
Net interest expense	$37	$31	$74	$64

Interest expense associated with unproved oil and gas properties is capitalized into oil and gas properties. Capitalized interest decreased $5 million and $9 million for the three and six months ended June 30, 2013, as compared to the same periods of 2012, due to a reduction in our average balance of unproved oil and gas properties.

Commodity Derivative Income (Expense). The fluctuations in commodity derivative income from period to period are due to the volatility of oil and natural gas prices and changes in our outstanding derivative instruments during these periods.

Taxes. The effective tax rates for the three months ended June 30, 2013 and 2012 were 38.1% and 37.0%, respectively. The effective tax rates for the six months ended June 30, 2013 and 2012 were 37.9% and 37.1%, respectively.

Results of Discontinued Operations - Malaysia and China

Revenues. Our international revenues are primarily from the sale of crude oil. Substantially all of the crude oil from our offshore operations in Malaysia and China is produced into FPSOs or onshore storage terminals, 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 FPSOs or onshore storage terminals. As a result, the timing of liftings may impact period-to-period results.

Revenues from discontinued operations of $188 million for the second quarter of 2013 were 32% lower than the comparable period of 2012 due primarily to fewer liftings combined with lower realized oil prices. Crude oil liftings were down 29% in the second quarter of 2013 compared to the second quarter of 2012. The following table reflects our production from discontinued operations and average realized commodity prices for the following periods:

	Three Months Ended June 30,		Percentage Increase (Decrease)	Six Months Ended June 30,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
Production/Liftings:						
Crude oil and condensate (MBbls)	1,805	2,553	(29)%	4,354	4,859	(10)%
Natural gas (Bcf)	—	0.2	—	0.2	0.4	(45)%
Total (MBOE)	1,805	2,590	(30)%	4,393	4,929	(11)%
Average Realized Prices:						
Crude oil and condensate (per Bbl)	$104.28	$108.07	(4)%	$107.61	$113.34	(5)%
Natural gas (per Mcf)	—	3.98	—	3.76	4.15	(9)%

Crude oil equivalent (per BOE)	104.28	106.88	(2	)%	106.88	112.09	(5	)%

Production. Our second quarter 2013 total production from discontinued operations decreased 30% over the comparable period of 2012. Approximately 70% of the decrease is due to natural decline. The remainder of the decrease is due to timing of liftings and the terms of our production sharing contracts (PSCs) in Malaysia, which reduce entitled production as we reach certain cost recovery milestones.

Operating Expenses. The following tables present information about our operating expenses for our discontinued operations for the following periods:

	Unit-of-Production Three Months Ended June 30,		Percentage Increase (Decrease)	Total Amount Three Months Ended June 30,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
	(Per BOE)			(In millions)		
Lease operating	$18.78	$9.54	97 %	$34	$25	37 %
Production and other taxes	36.17	27.94	29 %	65	73	(10)%
Depreciation, depletion and amortization	30.43	26.02	17 %	55	67	(19)%
General and administrative	2.81	0.74	280 %	5	1	163 %
Total operating expenses	$88.18	$64.23	37 %	$159	$166	(4)%

Our operating expenses for discontinued operations for the three months ended June 30, 2013, stated on a per BOE basis, increased 37% over the comparable period of 2012. The components of the period-to-period change are as follows:

- LOE includes normally recurring expenses to operate and produce our oil and natural gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. LOE per BOE increased 97% ($9.24 per BOE) due to higher service costs related to offshore support operations in Malaysia and mostly-fixed fees associated with producing into onshore storage terminals in Malaysia combined with fewer liftings.
- Production and other taxes per BOE increased by 29% due to the terms of our PSCs in Malaysia, which increase production tax rates subsequent to reaching certain cost recovery milestones. We expect the elevated production tax rates to continue as the majority of our fields in Malaysia are now subject to these higher rates.
- Total depreciation, depletion and amortization (DD&A) expense decreased 19% due to a combination of an increase in the average DD&A rate, which was more than offset by a 30% decrease in liftings during the second quarter of 2013, as compared to the second quarter of 2012. Our average quarterly DD&A rate per BOE increased 17% when compared to the quarterly rate for the comparative period in 2012. The increase was primarily due to the costs of unsuccessful wells offshore Malaysia and China being included in costs subject to amortization in the second quarter of 2013 without a related increase in reserves.
- G&A expense increased approximately $4 million ($2.07 per BOE) primarily due to increased employee-related and other costs associated with our decision to explore strategic alternatives for our international businesses.

	Unit-of-Production Six Months Ended June 30,		Percentage Increase (Decrease)	Total Amount Six Months Ended June 30,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
	(Per BOE)			(In millions)		
Lease operating	$15.76	$10.03	57 %	$69	$50	40 %
Production and other taxes	38.24	27.34	40 %	168	135	25 %
	29.50	25.91	14 %	130	127	1 %

Depreciation, depletion and amortization								
General and administrative	1.35	0.49	176	%	6	2	147	%
Total operating expenses	$84.86	$63.76	33	%	$373	$314	19	%

Our operating expenses for discontinued operations for the six months ended June 30, 2013, stated on a per BOE basis, increased 33% over the comparable period of 2012. The components of the period-to-period change are as follows:

- LOE per BOE increased 57% ($5.73 per BOE) due to increased service costs related to offshore support operations in Malaysia and mostly-fixed fees associated with producing into onshore storage terminals in Malaysia combined with fewer liftings.

- Production and other taxes per BOE increased by 40% due to the terms of our PSCs in Malaysia, which increase production tax rates subsequent to reaching certain cost recovery milestones. We expect the elevated production tax rates to continue as the majority of our fields in Malaysia are now subject to these higher rates.
- Our average DD&A rate per BOE increased 14% when compared to the rate for the comparative period in 2012. The increase was primarily due to the costs of unsuccessful wells offshore Malaysia and China being included in costs subject to amortization in the second quarter of 2013 without a related increase in reserves.
- G&A expense increased approximately $4 million ($0.86 per BOE) primarily due to increased employee-related costs and legal fees associated with our decision to explore strategic alternatives for our international businesses.

Liquidity and Capital Resources

The following discussion is inclusive of both our continuing and discontinued operations, unless otherwise noted.

We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this through successful drilling programs and property acquisitions, which require substantial capital expenditures. Lower prices for oil, natural gas and NGLs 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 and our ability to borrow and raise additional capital, as further described below.

We establish a capital budget for each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are created based upon our estimate of internally generated sources of cash, which includes cash flows from operations and if applicable, non-strategic asset sales, as well as available borrowing capacity under our credit arrangements. Approximately 84% of our expected 2013 domestic oil and gas production (excluding NGLs) is hedged. Our 2013 capital budget, excluding estimated capitalized interest and overhead of approximately $182 million, is expected to be approximately $1.9 billion and focuses on projects with higher rates of return, which we believe will generate and lay the foundation for liquids production growth in 2014 and thereafter. Of the total 2013 capital budget, approximately $1.5 billion is allocated to our continuing operations, substantially all of which is allocated to oil or liquids-rich projects.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results; oil, natural gas and NGL prices; industry conditions; the prices and availability of goods and services; the extent to which properties are acquired or non-strategic assets sold. We believe we have the operational flexibility to react quickly to changes in circumstances and our cash flows from operations.

We expect to fund our 2013 capital program with cash flows from operations, available borrowing capacity under our credit arrangements and proceeds from non-strategic asset sales during the year (including the potential sale of our international businesses). We believe that our liquidity position and ability to generate cash flows from our asset portfolio will be adequate to fund 2013 operations.

Credit Arrangements. We maintain a revolving credit facility of $1.4 billion that matures in June 2018, as well as money market lines of credit of $195 million, for a total borrowing capacity of $1.6 billion at June 30, 2013. Our outstanding long-term debt at June 30, 2013 consisted of senior and senior subordinated notes, which totaled $3.05 billion, as well as LIBOR and money market lines of credit, which totaled $231 million. At June 30, 2013, we had no scheduled maturities of senior notes or senior subordinated notes until 2018. As of June 30, 2013, we had $70 million of undrawn letters of credit outstanding under our credit facility. Additionally, as of June 30, 2013, we had $2 million of other undrawn letters of credit outstanding. For a more detailed description of the terms of our credit arrangements and senior and senior subordinated notes, please see Note 9, “Debt,” to our consolidated financial statements appearing earlier in this report.

As of July 22, 2013, our available borrowing capacity under our credit arrangements was approximately $1.2 billion, and we had the following:

- $315 million of borrowings under our credit facility;
- $70 million of letters of credit outstanding under our credit facility, issued to satisfy commitments under our PSCs in Malaysia;
- no outstanding borrowings under our money market lines of credit; and
- $2 million in other undrawn letters of credit outstanding.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments as well as the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. We

anticipate that our 2013 capital investment levels will exceed our estimate of cash flows from operations and plan on using available capacity under our credit arrangements and proceeds from non-strategic asset sales (including the potential sale of our international businesses) to fund any shortfall.

At June 30, 2013, we had negative working capital of $217 million compared to negative working capital of $93 million at December 31, 2012. The changes in our working capital are primarily a result of the timing of the collection of receivables, changes in the fair value of our derivative positions, the timing of crude oil liftings in our international operations, drilling activities, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Cash Flows from Operations. Cash flows from operations are our primary source of capital and liquidity and are primarily affected by the sale of our oil, natural gas and NGLs, as well as commodity prices, net of the effects of derivative contract settlements and changes in working capital. We sell substantially all of our oil, natural gas and NGLs 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 24 to 36 months. As of June 30, 2013, we had no open derivative contracts for NGLs. See “—Oil and Gas Hedging” below.

We typically receive the cash associated with oil and gas sales within 45 to 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.

Our net cash flows from operations were $610 million (includes $138 million of cash flows from discontinued operations) for the six months ended June 30, 2013, an increase of $35 million compared to net cash flows from operations of $575 million for the same period in 2012.

Cash Flows used in Investing Activities. Net cash used in investing activities for the six months ended June 30, 2013 was $873 million compared to $568 million for the same period in 2012. During the six months ended June 30, 2013 and 2012, we spent approximately $893 million and $897 million for additions to property and equipment, respectively. During the six months ended June 30, 2013, we received proceeds of $19 million from sales of oil and gas properties as compared to proceeds of $329 million for the comparable period of 2012.

Cash Flows from Financing Activities. Net cash provided by financing activities for the six months ended June 30, 2013 was $226 million compared to $573 million for the same period in 2012. During the six months ended June 30, 2013, we increased our borrowings under our revolving credit facility by $231 million.

Capital Expenditures. Our capital investments were approximately $1.0 billion for the first six months of both 2013 and 2012. These amounts exclude acquisitions and recorded asset retirement obligations, both of which were immaterial in the first six months of 2013 and 2012. During the first six months of 2013, we invested $631 million in domestic exploitation and development, $124 million in domestic exploration (exclusive of leasehold activity), $10 million in leasing domestic proved and unproved property (leasehold) and $190 million related to our discontinued operations. During the first six months of 2012, we invested $725 million in domestic exploitation and development, $102 million in domestic exploration (exclusive of leasehold activity), $44 million in leasing domestic proved and unproved property (leasehold) and $86 million related to our discontinued operations.

Commitments under Joint Operating Agreements. Most of our properties are operated through joint ventures under joint operating or similar agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a “working interest” basis. The joint operating agreement

provides remedies to the operator if a non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Contractual Obligations

The table below summarizes our significant contractual obligations by maturity as of June 30, 2013.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
	(In millions)				
Continuing Operations					
Debt:					
Revolving credit facility	$ 140	$ —	$ —	$ 140	$ —
Money market lines of credit	91	—	—	91	—
5¾% Senior Notes due 2022	750	—	—	—	750
5 % Senior Notes due 2024	1,000	—	—	—	1,000
7 % Senior Subordinated Notes due 2018	600	—	—	600	—
6 % Senior Subordinated Notes due 2020	700	—	—	—	700
Total debt	3,281	—	—	831	2,450
Other obligations:					
Interest payments	1,605	194	583	342	486
Net derivative (assets) liabilities	(119)	(59)	(60)	—	—
Asset retirement obligations	103	2	7	9	85
Operating leases and other [1]	204	89	69	23	23
Firm transportation	485	79	224	123	59
Total other obligations	2,278	305	823	497	653
Total contractual obligations from continuing operations	$ 5,559	$ 305	$ 823	$ 1,328	$ 3,103
Discontinued Operations					
Other obligations:					
Asset retirement obligations	$ 44	$ 5	$ 26	$ 6	$ 7
Operating leases and other [2]	289	241	42	6	—
Oil and gas activities [3]	93	—	—	—	—
Total contractual obligations from discontinued operations	$ 426	$ 246	$ 68	$ 12	$ 7

(1) Includes agreements for office space, drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for office space and drilling rigs, and are included at the gross contractual value. Due to our various working interests where the drilling rig 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.

(2) Includes agreements for office space, platform construction, drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for platform construction 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 related commitments. At June 30, 2013, these work-related commitments totaled $93 million, all of which were attributable to our international businesses. Actual amounts by maturity are not included because their timing cannot be accurately predicted.

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We have various oil and gas production volume delivery commitments that are related to our continuing operations. There have been no material changes with respect to our volumetric delivery commitments subsequent to December 31, 2012. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations" in our Annual Report on Form 10-K for the year ended December 31, 2012.

For further information about our credit arrangements, senior notes, senior subordinated notes and commitments under joint operating agreements, see “— Liquidity and Capital Resources” above.

Oil and Gas Hedging

We use derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. We generally hedge a substantial, but varying, portion of our anticipated future domestic oil and gas production for the next 24 to 36 months. As of June 30, 2013, we had no outstanding derivative contracts related to our NGL production or production associated with our discontinued operations. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may use basis contracts to hedge the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes.

See the discussion and tables in Note 5, “Derivative Financial Instruments,” and Note 8, “Fair Value Measurements,” to our consolidated financial statements appearing earlier in this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open positions and the estimated fair market value of those positions as of June 30, 2013.

Between July 1, 2013 and July 22, 2013, we entered into additional derivative contracts as set forth below.

Crude Oil

		NYMEX Contract Price Per Bbl			
				Collars	
Period and Type of Instrument	Volume in MBbls	Swaps (Weighted Average)	Sold Puts (Weighted Average)	Floors (Weighted Average)	Ceilings (Weighted Average)
2014:					
Fixed-price swaps	1,370	$90.49	—	—	—
Fixed-price swaps with sold puts	1,095	95.84	$75.00	—	—
2015:					
Fixed-price swaps with sold puts	1,460	90.09	66.00	—	—

Accounting for Hedging Activities. We do not designate future price-risk management activities as accounting hedges. Because derivative contracts 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 non-cash volatility in our reported earnings during periods of commodity price volatility. As of June 30, 2013, we had net derivative assets of $119 million, of which 36%, based on total hedged volumes, 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 their fair value as of June 30, 2013. We use credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. 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, 2012 and Note 5, "Derivative Financial Instruments," and Note 8, "Fair Value Measurements," to our consolidated financial statements appearing earlier in this report for additional discussion of the accounting applicable to our oil and gas derivative contracts.

New Accounting Requirements

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance requires disclosure of both gross and net information about instruments and transactions eligible for offset arrangement. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. We adopted the guidance in the quarter ended March 31, 2013. Adoption of the additional disclosures regarding offsetting assets and liabilities did not have a material impact on our financial position or results of operations.

In February 2013, the FASB issued guidance regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The guidance is effective for interim and annual periods beginning after December 15, 2012. We adopted the guidance in the quarter ended March 31, 2013. Adoption of the new reporting guidance did not have a material impact on our financial position or results of operations as we did not have reclassifications during the periods presented.

Forward-Looking Information

This report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts included in this report, are forward-looking, including information relating 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. Forward-looking statements are typically identified by use of terms such as “may,” “believe,” “expect,” “anticipate,” “intend,” “estimate,” “project,” “target,” “goal,” “plan,” “shou “predict,” “potential” and similar expressions that convey the uncertainty of future events or outcomes. 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, natural gas and NGL prices and demand;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations, including those related to hydraulic fracturing and climate change;
- land, legal and ownership complexities inherent in the U.S. oil and gas industry;
- the impact of regulatory approvals;
- the availability and volatility 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;
- our commodity hedging arrangements as compared to actual commodity prices;
- the volatility in the commodity futures market;
- the availability of storage, transportation and refining capacity for the crude oil we produce in the Uinta Basin;
- drilling risks and results;
- the prices of goods and services;
- the availability of drilling rigs and other support services;
- global events that may impact our domestic and international operating contracts, markets and prices;
- labor conditions;
- weather conditions;
- environmental liabilities that are not covered by an effective indemnity or insurance;

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- competitive conditions;
- terrorism or civil or political unrest in a region or country;
- our ability to monetize non-strategic assets, pay debt and the impact of changes in our investment ratings;
- electronic, cyber or physical security breaches;
- changes in tax rates;
- inflation rates;
- uncertainties and changes in estimates of reserves;
- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources;
- the availability (or lack thereof) of acquisition, disposition or combination opportunities; and
- the additional factors discussed elsewhere in our public filings and press releases, including the factors discussed in "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" included in our 2012 Annual Report on Form 10-K.

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. 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.

BOE. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate and 42 gallons for NGLs.

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.

Liquids. Crude oil and NGLs.

Liquids-rich. Formations that contain crude oil or NGLs instead of, or as well as, natural gas.

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

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

NGL. Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasolines.

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 natural 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.

SEC pricing. The unweighted average first-day-of-the-month commodity price for crude oil or natural gas for the prior 12 months, adjusted for market differentials. The SEC provides a complete definition of prices in “Modernization of Oil and Gas Reporting” (Final Rule).

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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Oil, Natural Gas and NGL Prices

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 the use of hedging arrangements limits the downside risk of adverse price movements, their use also may limit future benefits 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, 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. At June 30, 2013, eight of our 15 counterparties accounted for approximately 85% of our estimated future hedged production with no single counterparty accounting for more than 17% of that production. For a further discussion of our hedging activities, see the information under the caption “Oil and Gas Hedging” in Item 2 appearing earlier in 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, 2013, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility and money market lines of credit	$—	$231
7 % Senior Subordinated Notes due 2018	600	—
6 % Senior Subordinated Notes due 2020	695	—
5¾% Senior Notes due 2022	750	—
5 % Senior Notes due 2024	1,000	—
	$3,045	$231

We consider our interest rate exposure to be minimal because 93% of our obligations were at fixed rates as of June 30, 2013. Our variable rate debt is currently at interest rates of 2% or less.

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 flows, to be immaterial. We did not have any open derivative contracts related to foreign currencies at June 30, 2013.

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 our 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 our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2013.

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 our Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the second quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based upon 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

In August 2010, we received a Notice of Violation (NOV) from the Environmental Protection Agency (EPA) alleging that we failed to provide adequate financial assurance for water injection wells falling under EPA jurisdiction that are

located at our Monument Butte field in Duchesne County, Utah (Monument Butte). The injection wells are part of an enhanced oil recovery project designed to optimize production from Monument Butte. Regulations under the Safe Drinking Water Act (SDWA) require operators of injection wells to file proof of financial assurance annually to cover the costs to plug and abandon the injection wells. The NOV alleges that our 2010 and 2009 filings (for 2009 and 2008) did not meet the financial ratio tests that are acceptable as one form of required financial assurance under SDWA regulations. The NOV was completely administrative in nature and did not contain any allegations of environmental spills, releases or pollution. Upon receipt of the NOV, we promptly complied with the EPA's request to put in place alternate financial assurance for the wells even though we in fact believed we did meet the financial ratio tests. We held preliminary discussions with the EPA regarding potential settlement of this matter; however, the EPA

determined that the NOV could not be resolved within the EPA's settlement authority under the SDWA and required a referral to the Department of Justice (DOJ). We intend to vigorously defend against the DOJ's allegations. Although the outcome of this matter cannot be predicted with certainty, we do not expect it to have a material adverse effect on our financial position, cash flows or results of operations.

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 (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) 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.

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, 2012.

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, 2013.

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, 2013	2,930	$22.41	—	—
May 1 — May 31, 2013	14,129	22.80	—	—
June 1 — June 30, 2013	4,944	24.26	—	—
Total	22,003	$23.08	—	—

(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.

Item 6. Exhibits

Exhibit Number	Description
3.1	Third 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, 2011 (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 July 25, 2013 (File No. 1-12534))
10.1	Newfield Exploration Company Amended and Restated 2011 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield's Current Report on Form 8-K filed on May 3, 2013 (File No. 1-12534))
*10.2	Third Amendment to Credit Agreement, dated as of June 25, 2013, by and among Newfield 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., DNB Bank ASA, Sumitomo Mitsui Banking Corporation and U.S. Bank National Association, as Co-Documentation Agents, and other Lenders thereto
*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 herewith.

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 26, 2013

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

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