NEWFIELD EXPLORATION CO /DE/
Form 10-Q
July 26, 2012

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, 2012

OR

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

For the Transition Period from to .

Commission File Number: 1-12534

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

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

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 o

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

| | | | |
|---|---|---|---|
| Large accelerated filer þ | Accelerated filer o | Non-accelerated filer o<br>(Do not check if a smaller reporting company) | Smaller reporting company o |

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

As of July 23, 2012, there were 134,983,369 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, 2012 | December 31, 2011 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $656 | $76 |
| Accounts receivable | 416 | 407 |
| Inventories | 104 | 90 |
| Derivative assets | 142 | 129 |
| Other current assets | 94 | 73 |
| Total current assets | 1,412 | 775 |
| Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,904 and $1,965 were excluded from amortization at June 30, 2012 and December 31, 2011, respectively) | 15,166 | 14,526 |
| Less accumulated depreciation, depletion and amortization | (6,965) | (6,506) |
| Total property and equipment, net | 8,201 | 8,020 |
| | | |
| Derivative assets | 81 | 61 |
| Long-term investments | 55 | 52 |
| Deferred taxes | 36 | 28 |
| Other assets | 59 | 55 |
| Total assets | $9,844 | $8,991 |
| | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current liabilities: | | |
| Accounts payable | $78 | $112 |
| Accrued liabilities | 719 | 687 |
| Advances from joint owners | 19 | 45 |
| Asset retirement obligations | 10 | 10 |
| Derivative liabilities | 7 | 50 |
| Deferred taxes | 47 | 28 |
| Total current liabilities | 880 | 932 |
| | | |
| Other liabilities | 42 | 44 |
| Derivative liabilities | 6 | 3 |
| Long-term debt | 3,595 | 3,006 |
| Asset retirement obligations | 137 | 135 |
| Deferred taxes | 993 | 951 |
| Total long-term liabilities | 4,773 | 4,139 |
| | | |
| Commitments and contingencies (Note 11) | — | — |
| | | |
| Stockholders' equity: | | |
| Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued) | — | — |

| | | |
|---|---|---|
| Common stock ($0.01 par value, 200,000,000 shares authorized at June 30, 2012 and December 31, 2011; 136,464,457 and 136,379,381 shares issued at June 30, 2012 and December 31, 2011, respectively) | 1 | 1 |
| Additional paid-in capital | 1,508 | 1,495 |
| Treasury stock (at cost, 1,488,257 and 1,694,623 shares at June 30, 2012 and December 31, 2011, respectively) | (45) | (50) |
| Accumulated other comprehensive loss | (8) | (10) |
| Retained earnings | 2,735 | 2,484 |
| Total stockholders' equity | 4,191 | 3,920 |
| Total liabilities and stockholders' equity | $9,844 | $8,991 |

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

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NEWFIELD EXPLORATION COMPANY

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

| | Three Months Ended June 30, 2012 | Three Months Ended June 30, 2011 | Six Months Ended June 30, 2012 | Six Months Ended June 30, 2011 |
|---|---|---|---|---|
| Oil and gas revenues | $ 628 | $ 621 | $ 1,306 | $ 1,166 |
| Operating expenses: | | | | |
| Lease operating | 129 | 125 | 256 | 218 |
| Production and other taxes | 88 | 79 | 171 | 150 |
| Depreciation, depletion and amortization | 239 | 173 | 465 | 339 |
| General and administrative | 61 | 44 | 106 | 81 |
| Total operating expenses | 517 | 421 | 998 | 788 |
| Income from operations | 111 | 200 | 308 | 378 |
| Other income (expenses): | | | | |
| Interest expense | (49) | (41) | (100) | (81) |
| Capitalized interest | 18 | 19 | 36 | 37 |
| Commodity derivative income (expense) | 135 | 169 | 159 | (13) |
| Other | (1) | — | (2) | (1) |
| Total other income (expenses) | 103 | 147 | 93 | (58) |
| Income before income taxes | 214 | 347 | 401 | 320 |
| Income tax provision: | | | | |
| Current | 48 | 7 | 96 | 30 |
| Deferred | 31 | 121 | 54 | 88 |
| Total income tax provision | 79 | 128 | 150 | 118 |
| Net income | $ 135 | $ 219 | $ 251 | $ 202 |
| Earnings per share: | | | | |
| Basic | $ 1.00 | $ 1.64 | $ 1.86 | $ 1.52 |
| Diluted | $ 1.00 | $ 1.62 | $ 1.85 | $ 1.50 |
| Weighted-average number of shares outstanding for basic earnings per share | 134 | 134 | 134 | 133 |
| Weighted-average number of shares outstanding for diluted earnings per share | 135 | 135 | 135 | 135 |

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

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Net income | $135 | $219 | $251 | $202 |
| Other comprehensive income: | | | | |
| Unrealized gain on investments, net of tax | — | 1 | 2 | 4 |
| Other comprehensive income, net of tax | — | 1 | 2 | 4 |
| Comprehensive income | $135 | $220 | $253 | $206 |

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

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NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)
(Unaudited)

| | Six Months Ended June 30, 2012 | Six Months Ended June 30, 2011 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income | $251 | $202 |
| | | |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 465 | 339 |
| Deferred tax provision | 54 | 88 |
| Stock-based compensation | 17 | 14 |
| Commodity derivative (income) expense | (159) | 13 |
| Cash receipts on derivative settlements, net | 86 | 95 |
| Other non-cash charges | 3 | 3 |
| Changes in operating assets and liabilities: | | |
| Increase in accounts receivable | (5) | (6) |
| Increase in inventories | (12) | (26) |
| Increase in other current assets | (20) | (19) |
| Increase in other assets | (1) | (4) |
| Increase (decrease) in accounts payable and accrued liabilities | (76) | 29 |
| Increase (decrease) in advances from joint owners | (26) | 4 |
| Decrease in other liabilities | (2) | (3) |
| Net cash provided by operating activities | 575 | 729 |
| | | |
| Cash flows from investing activities: | | |
| Additions to oil and gas properties | (875) | (1,077) |
| Acquisitions of oil and gas properties | (9) | (311) |
| Proceeds from sales of oil and gas properties | 329 | 130 |
| Additions to furniture, fixtures and equipment | (13) | (10) |
| Redemptions of investments | — | 1 |
| Net cash used in investing activities | (568) | (1,267) |
| | | |
| Cash flows from financing activities: | | |
| Proceeds from borrowings under credit arrangements | 1,663 | 2,371 |
| Repayments of borrowings under credit arrangements | (1,749) | (1,786) |
| Proceeds from issuance of senior notes | 1,000 | — |
| Debt issue costs | (10) | (8) |
| Repayment of senior subordinated notes | (325) | — |
| Proceeds from issuances of common stock | — | 11 |
| Purchases of treasury stock, net | (6) | (15) |
| Net cash provided by financing activities | 573 | 573 |
| | | |
| Increase in cash and cash equivalents | 580 | 35 |
| Cash and cash equivalents, beginning of period | 76 | 39 |
| Cash and cash equivalents, end of period | $656 | $74 |

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

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NEWFIELD EXPLORATION COMPANY

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

| | Common Stock | | Treasury Stock | | Additional Paid-in | Retained | Accumulated Other Comprehensive Income | Total Stockholders' |
|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Capital | Earnings | (Loss) | Equity |
| Balance, December 31, 2011 | 136.4 | $ 1 | (1.7) | $ (50) | $ 1,495 | $ 2,484 | $ (10) | $ 3,920 |
| Issuances of common stock | 0.1 | — | | | — | | | — |
| Stock-based compensation | | | | | 24 | | | 24 |
| Treasury stock, net | | | 0.2 | 5 | (11) | | | (6) |
| Net income | | | | | | 251 | | 251 |
| Other comprehensive income, net of tax | | | | | | | 2 | 2 |
| Balance, June 30, 2012 | 136.5 | $ 1 | (1.5) | $ (45) | $ 1,508 | $ 2,735 | $ (8) | $ 4,191 |

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

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NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent 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 onshore Texas. Internationally, we focus on offshore oil developments in Malaysia and China.

Our financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and 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" or "our" are to Newfield Exploration Company and its subsidiaries.

These unaudited consolidated financial statements reflect, in the opinion of our management, all adjustments, consisting only of normal and recurring adjustments, necessary to 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 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, 2011.

Dependence on Oil and Natural Gas 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 and natural gas. Historically, the energy markets have been very volatile, and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil or natural gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and natural gas reserves that we can economically produce.

Use of Estimates

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

Investments

Investments consist primarily of debt and equity securities, as well as auction rate securities, a majority of which are classified as “available-for-sale” and stated at fair value. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported as a separate component within the consolidated statement of comprehensive income. 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 $0.3 million and $0.2 million for the three-month periods ended June 30, 2012 and 2011, respectively, and approximately $1 million for each of the six-month periods ended June 30, 2012 and 2011.

Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and gas operations and oil produced in our operations offshore Malaysia and China but not sold. Inventories are carried at the lower of cost or market. Substantially all of the crude oil from our operations offshore Malaysia and China is produced into FPSOs and sold periodically as barge quantities are accumulated. The product inventory consisted of approximately 335,000 barrels and 239,000 barrels of crude oil valued at cost of $26 million and $19 million at June 30, 2012 and December 31, 2011, respectively. Cost for purposes of the carrying value of oil inventory is the sum of production costs and depletion expense.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $27 million of internal costs during both three-month periods ended June 30, 2012 and 2011 and $58 million and $51 million during the six-month periods ended June 30, 2012 and 2011, 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 and natural gas reserve estimation requirements, which requires use of the unweighted average first-day-of-the-month commodity prices for the prior 12 months, adjusted for market differentials applicable to our reserves (including the effects of hedging contracts that are designated for hedge accounting, if any); plus
- the lower of cost or estimated fair value of properties not included in the costs being amortized, if any; less
- related income tax effects.

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 properties increases when oil and natural gas prices decrease significantly for a prolonged period of time or if we have substantial downward revisions in our estimated proved reserves. At June 30, 2012, the ceiling value of our reserves was calculated based upon the unweighted average first-day-of-the-month commodity prices for the prior 12 months of $3.15 per MMBtu for natural gas and $95.79 per barrel for oil, adjusted for market differentials. Using these prices, the cost center ceilings with respect to our properties in the U.S., Malaysia and China exceeded the net capitalized costs of the respective properties. As such, no ceiling test writedowns were required at June 30, 2012.

Accounting for Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the present value of the asset retirement cost in oil and gas properties in the period in which the ARO is incurred. Settlements include payments made to satisfy the AROs, as well as transfer of the ARO to purchasers of our divested properties.

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In general, the amount of an ARO and the costs capitalized will equal the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds, and the additional capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization expense on our consolidated statement of net income.

The change in our ARO for the six months ended June 30, 2012 is set forth below (in millions):

| | | |
|---|---|---|
| Balance at January 1, 2012 | $ | 145 |
| Accretion expense | | 6 |
| Additions | | 5 |
| Revisions | | 6 |
| Settlements | | (15) |
| Balance at June 30, 2012 | | 147 |
| Less: Current portion of ARO at June 30, 2012 | | (10) |
| Total long-term ARO at June 30, 2012 | $ | 137 |

Income Taxes

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

Derivative Financial Instruments

We account for our derivative activities by applying authoritative accounting and reporting guidance, which requires that every derivative instrument be recorded on the consolidated balance sheet as either an asset or a liability measured at its fair value and that changes in the derivative’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. All of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price-risk management activities as accounting hedges under the accounting guidance and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings. We periodically utilize derivatives to manage our exposure to variable interest rates.

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities. See Note 4, “Derivative Financial Instruments,” for a more detailed discussion of our derivative activities.

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

New Accounting Requirements

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

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance will require disclosure of gross information 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 do not expect adoption of the additional disclosures regarding offsetting assets and liabilities to have a material impact on our financial position or results of operations.

2. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted-average number of shares of common stock (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. Please see Note 10, "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, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In millions, except per share data) | | | |
| Income (numerator): | | | | |
| Net income — basic and diluted | $135 | $219 | $251 | $202 |
| Weighted-average shares (denominator): | | | | |
| Weighted-average shares — basic | 134 | 134 | 134 | 133 |
| Dilution effect of stock options and unvested restricted stock and restricted stock units outstanding at end of period(1) | 1 | 1 | 1 | 2 |
| Weighted-average shares — diluted | 135 | 135 | 135 | 135 |

| | | | | |
|---|---|---|---|---|
| Earnings per share: | | | | |
| Basic earnings per share | $1.00 | $1.64 | $1.86 | $1.52 |
| Diluted earnings per share | $1.00 | $1.62 | $1.85 | $1.50 |

(1) The calculation of shares outstanding for diluted EPS for the three and six months ended June 30, 2012 excludes the effect of 3.0 million unvested restricted stock or restricted stock units and stock options, and the calculation of shares outstanding for diluted EPS for the three and six months ended June 30, 2011 excludes the effect of 0.2 million and 1.0 million, respectively, unvested restricted stock or restricted stock units and stock options because including the effect would be anti-dilutive.

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

3. Oil and Gas Assets:

Property and Equipment

Property and equipment consisted of the following at:

| | June 30, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| Oil and gas properties: | | |
| Subject to amortization | $13,112 | $12,423 |
| Not subject to amortization | 1,904 | 1,965 |
| Gross oil and gas properties | 15,016 | 14,388 |
| Accumulated depreciation, depletion and amortization | (6,888) | (6,436) |
| Net oil and gas properties | 8,128 | 7,952 |
| Other property and equipment | 150 | 138 |
| Accumulated depreciation and amortization | (77) | (70) |
| Net other property and equipment | 73 | 68 |
| Total property and equipment, net | $8,201 | $8,020 |

The following is a summary of our oil and gas properties not subject to amortization as of June 30, 2012. 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 will take significantly longer than four years. At June 30, 2012, approximately 75% of oil and gas properties not subject to amortization were associated with our unconventional resource plays.

| | Costs Incurred In | | | | |
|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2009 and prior | Total |
| | | | (In millions) | | |
| Acquisition costs | $79 | $305 | $306 | $422 | $1,112 |
| Exploration costs | 289 | 65 | 22 | 35 | 411 |
| Development costs | 29 | 63 | 25 | 37 | 154 |
| Fee mineral interests | — | — | — | 23 | 23 |
| Capitalized interest | 36 | 78 | 55 | 35 | 204 |
| Total oil and gas properties not subject to amortization | $433 | $511 | $408 | $552 | $1,904 |

Non-Strategic Asset Sales

During the six months ended June 30, 2012 and the year ended December 31, 2011, we sold certain non-strategic assets for approximately $329 million and $434 million, 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.

4. Derivative Financial Instruments:

Commodity Derivative Instruments

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

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

All of our derivative contracts are carried at their fair value on our consolidated balance sheet under the captions “Derivative assets” and “Derivative liabilities.” Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model. Please see Note 7, “Fair Value Measurements.” We recognize all realized and unrealized gains and losses related to these contracts on a mark-to-market basis in our consolidated statement of net income under the caption “Commodity derivative income (expense).” Settlements of derivative contracts are included in operating cash flows on our consolidated statement of cash flows.

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

At June 30, 2012, we had outstanding contracts with respect to our future production that were not designated for hedge accounting as set forth in the tables below.

Natural Gas

| | | NYMEX Contract Price Per MMBtu | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Collars | | | | Estimated Fair Value Asset |
| | | Swaps | Additional Put | | Floors | | Ceilings | | |
| Period and Type of Contract | Volume in MMMBtus | (Weighted Average) | Range | Weighted Average | Range | Weighted Average | Range | Weighted Average | (Liability) (In millions) |
| July 2012 – September 2012 | | | | | | | | | |
| Price swap contracts | 10,120 | $4.17 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | $ 13 |
| Price swap contracts | (A) | 2.67 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | (2 ) |
| 3-Way collar contracts | 23,000 | — | $3.50-$4.50 | $4.30 | $5.00-$5.75 | $5.44 | $5.20-$7.00 | $6.26 | 26 |
| October 2012 – December 2012 | | | | | | | | | |
| Price swap contracts | 11,340 | 3.19 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | 2 |
| Price swap contracts | (A) | 2.72 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | (6 ) |
| 3-Way collar contracts | 15,070 | — | 3.50-4.50 | 4.19 | 5.00-6.00 | 5.51 | 5.20-7.55 | 6.41 | 18 |
| January 2013 – December 2013 | | | | | | | | | |
| Price swap contracts | 54,750 | 4.08 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | 28 |
| Price swap contracts | (A) | 3.45 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | (5 ) |
| | 39,530 | — | 3.50-4.50 | 4.04 | 5.00-6.00 | 5.44 | 6.00-7.55 | 6.48 | 43 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 3-Way collar contracts | | | | | | | | | |
| January 2014 – December 2014 | | | | | | | | | |
| Price swap contracts | 54,750 | 3.85 | ¾ | ¾ | ¾ | ¾ | ¾ | ¾ | (5 ) |
| | | | | | | | | | $ 112 |

(A) During the first quarter of 2012, natural gas spot market prices were below the puts we sold on our three-way collars 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 fixed-price swap contracts in the over-the-counter market that effectively prevented any further erosion in the value of our natural gas three-way collars. The new swap contracts added during the first quarter of 2012 were for the same volumes as our July through December 2012 and the full-year 2013 three-way collar contracts. The economics from the combination of these additional fixed-price swap contracts and our natural gas three-way collar contracts will result in effective average fixed prices of $3.81, $4.04, and $4.85 per MMBtu for the third and fourth quarters of 2012 and the full-year 2013, respectively, as long as natural gas spot prices for the respective time periods settle below the puts we sold on our three-way collar contracts.

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

Oil

| | | NYMEX Contract Price Per Bbl | | | | | | Estimated Fair Value |
|---|---|---|---|---|---|---|---|---|
| | | | | Collars | | | | |
| | | Additional Put | | Floors | | Ceilings | | |
| Period and Type of Contract | Volume in MBbls | Range | Weighted Average | Range | Weighted Average | Range | Weighted Average | Asset (Liability) (In millions) |
| July 2012 – September 2012 | | | | | | | | |
| 3-Way collar contracts | 3,220 | $55.00-$90.00 | $66.86 | $75.00-$100.00 | $82.96 | $88.20-$137.80 | $111.14 | $ 8 |
| October 2012 – December 2012 | | | | | | | | |
| 3-Way collar contracts | 3,220 | 55.00-90.00 | 66.86 | 75.00-100.00 | 82.96 | 88.20-137.80 | 111.14 | 10 |
| January 2013 – December 2013 | | | | | | | | |
| 3-Way collar contracts | 12,115 | 80.00 | 80.00 | 95.00 | 95.00 | 106.50-130.40 | 118.05 | 62 |
| January 2014 – December 2014 | | | | | | | | |
| 3-Way collar contracts | 5,110 | 80.00 | 80.00 | 95.00 | 95.00 | 117.50-120.75 | 119.16 | 24 |
| | | | | | | | | $ 104 |

Basis Contracts

At June 30, 2012, we had natural gas basis contracts that were not designated for hedge accounting to lock in the differential between the NYMEX Henry Hub posted prices and those of our physical pricing points in the Rocky Mountains and Mid-Continent, as set forth in the table below.

| | Rocky Mountains | | Mid-Continent | | |
|---|---|---|---|---|---|
| | Volume in MMMbtus | Weighted-Average Differential MMMBtus | Volume in MMMbtus | Weighted-Average Differential MMMBtus | Estimated Fair Value Asset (Liability) (In millions) |
| July 2012 – September 2012 | 1,230 | $ (0.91) | 4,600 | $ (0.55) | $ (3) |
| October 2012 – December 2012 | 1,230 | (0.91) | 4,600 | (0.55) | (3) |
| | | | | | $ (6) |

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.

| Type of Contract | Balance Sheet Location | June 30, 2012 | December 31, 2011 |
|---|---|---|---|
| | | (In millions) | |
| Derivatives not designated as hedging instruments: | | | |
| Natural gas contracts | Derivative assets – current | $ 95 | $ 133 |
| Oil contracts | Derivative assets – current | 50 | 1 |
| Basis contracts | Derivative assets – current | (3) | (5) |
| Natural gas contracts | Derivative assets – noncurrent | 27 | 61 |
| Oil contracts | Derivative assets – noncurrent | 54 | — |
| Natural gas contracts | Derivative liabilities – current | (4) | — |
| Oil contracts | Derivative liabilities – current | — | (45) |
| Basis contracts | Derivative liabilities – current | (3) | (5) |
| Natural gas contracts | Derivative liabilities – noncurrent | (6) | — |
| Oil contracts | Derivative liabilities – noncurrent | — | (3) |
| Total | | $ 210 | $ 137 |

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

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

| Type of Contract | Location of Gain (Loss) Recognized in Income | Three Months Ended June 30, 2012 | Three Months Ended June 30, 2011 | Six Months Ended June 30, 2012 | Six Months Ended June 30, 2011 |
|---|---|---|---|---|---|
| | | (In millions) | | | |
| Derivatives not designated as hedging instruments: | | | | | |
| Realized gain on natural gas contracts | Commodity derivative income (expense) | $ 54 | $ 62 | $ 98 | $ 130 |
| Realized loss on oil contracts | Commodity derivative income (expense) | — | (20) | (7) | (32) |
| Realized loss on basis contracts | Commodity derivative income (expense) | (2) | (2) | (5) | (3) |
| Total realized gain | | 52 | 40 | 86 | 95 |
| Unrealized loss on natural gas contracts | Commodity derivative income (expense) | (88) | (19) | (83) | (73) |
| Unrealized gain (loss) on oil contracts | Commodity derivative income (expense) | 169 | 148 | 151 | (35) |
| Unrealized gain on basis contracts | Commodity derivative income (expense) | 2 | — | 5 | — |
| Total unrealized gain (loss) | | 83 | 129 | 73 | (108) |
| Total | | $ 135 | $ 169 | $ 159 | $ (13) |

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, 2012, Bank of Montreal, Barclays Bank PLC, J Aron & Company, JPMorgan Chase Bank, N.A., Macquarie Bank Limited, and Morgan Stanley Capital Group Inc. were the counterparties with respect to approximately 85% of our estimated future hedged production, the largest of which was J Aron & Company, which accounted for 25% of our estimated future hedged production.

The counterparties to the majority of our derivative instruments also are 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.

5. Accounts Receivable:

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

| | June 30, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| Revenue | $310 | $301 |
| Joint interest | 98 | 96 |
| Other | 9 | 11 |
| Reserve for doubtful accounts | (1) | (1) |
| Total accounts receivable | $416 | $407 |

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

6. Accrued Liabilities:

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

| | June 30, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| Revenue payable | $95 | $94 |
| Accrued capital costs | 297 | 231 |
| Accrued lease operating expenses | 79 | 86 |
| Employee incentive expense | 36 | 61 |
| Accrued interest on debt | 67 | 52 |
| Taxes payable | 129 | 122 |
| Other | 16 | 41 |
| Total accrued liabilities | $719 | $687 |

7. Fair Value Measurements:

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value and requires that fair value measurements be classified and disclosed in one of the following categories:

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

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

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Our valuation models for derivative contracts are primarily industry-standard models (i.e., Black-Scholes) that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our valuation methodology for investments is a discounted cash flow model that considers various inputs including: (a) the coupon rate specified under the debt instruments, (b) the current credit ratings of the underlying issuers, (c) collateral characteristics and (d) risk adjusted discount rates. Level 3 instruments primarily include derivative instruments, such as basis swaps, commodity options including, price collars, floors and three-way collars (as of June 30, 2012, our options were comprised of only three-way collars) and some financial investments. Although we utilize third-party broker quotes to assess the reasonableness of our prices and valuation techniques 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.

Fair Value of Investments and Derivative Instruments

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

| | Fair Value Measurement Classification | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| | (In millions) | | | |
| As of December 31, 2011: | | | | |
| Investments available-for-sale: | | | | |
| Equity securities | $ 10 | $ — | $ — | $ 10 |
| Auction rate securities | — | — | 32 | 32 |
| Oil and gas derivative swap contracts | — | 66 | (10) | 56 |
| Oil and gas derivative option contracts | — | — | 81 | 81 |
| Total | $ 10 | $ 66 | $ 103 | $ 179 |
| As of June 30, 2012: | | | | |
| Money market fund investments | $ 430 | $ — | $ — | $ 430 |
| Investments available-for-sale: | | | | |
| Equity securities | 11 | — | — | 11 |
| Auction rate securities | — | — | 34 | 34 |
| Oil and gas derivative swap contracts | — | 25 | (6) | 19 |
| Oil and gas derivative option contracts | — | — | 191 | 191 |
| Total | $ 441 | $ 25 | $ 219 | $ 685 |

The determination of the fair values above incorporates various factors, which include not only the impact of our non-performance risk on our liabilities but also the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), 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, 2012, we held $34 million of auction rate securities maturing beginning in 2033 that are classified as a Level 3 fair value measurement. This amount reflects a decrease in the fair value of these investments of $11 million ($7 million net of tax), recorded under the caption “Accumulated other comprehensive loss” on our consolidated balance sheet. As of December 31, 2011, we held $32 million of auction rate securities, which reflected a decrease in the fair value of $13 million ($8 million net of tax). The debt instruments underlying our auction rate securities are mostly investment grade (rated BBB or better) and are guaranteed by the United States government or backed by private loan collateral. We do not believe the decrease in the fair value of these securities is permanent because we currently intend to hold these investments until the auction succeeds, the issuer calls the securities or the securities mature. Our current available borrowing capacity under our credit arrangements provides us the liquidity to continue to hold these securities.

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

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, 2011 | $30 | $48 | $78 |
| Total realized or unrealized gains (losses): | | | |
| Included in earnings | — | (8) | (8) |
| Included in other comprehensive income | 5 | — | 5 |
| Purchases, issuances and settlements: | | | |
| Settlements | — | (26) | (26) |
| Transfers in and out of Level 3 | — | — | — |
| Balance at June 30, 2011 | $35 | $14 | $49 |
| Change in unrealized losses included in earnings relating to investments and derivatives still held at June 30, 2011 | $— | $(12) | $(12) |
| Balance at January 1, 2012 | $32 | $71 | $103 |
| Total realized or unrealized gains (losses): | | | |
| Included in earnings | — | 157 | 157 |
| Included in other comprehensive income | 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 included in earnings relating to investments and derivatives still held at June 30, 2012 | $— | $141 | $141 |

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Commodity Derivatives. Our valuation models for 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 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 leads 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.

Auction Rate Securities. 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 the determination of the investments fair value, however, is market liquidity for these instruments. 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.

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

Quantitative Disclosures about Unobservable Inputs

| Instrument Type | Estimated Fair Value Asset (Liability) (In millions) | Quantitative Information about Level 3 Fair Value Measurements Valuation Technique | Unobservable Input | Range | | |
|---|---|---|---|---|---|---|
| Basis contracts | $ (6) | Discounted cash flow | NYMEX Natural gas price forward curve | $ 2.75 | - | $ 3.36 |
| | | | Physical pricing point forward curves | $ 2.44 | - | $ 3.21 |
| | | | Credit risk | 0.05 % | - | 0.64 % |
| Oil 3-way collar contracts | $ 104 | Option model | NYMEX Oil price forward curve | $ 81.80 | - | $ 88.71 |
| | | | Oil price volatility curves | 22.44 % | - | 40.74 % |
| | | | Credit risk | 0.02 % | - | 12.60 % |
| Natural gas 3-way collar contracts | $ 87 | Option model | NYMEX Natural gas price forward curve | $ 2.75 | - | $ 4.22 |
| | | | Natural gas price volatility curves | 25.31 % | - | 60.79 % |
| | | | Credit risk | 0.02 % | - | 4.17 % |

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, 2012 | December 31, 2011 |
|---|---|---|
| 5¾% Senior Notes due 2022 | $788 | $808 |
| 5 % Senior Notes due 2024 | 1,028 | — |
| 6 % Senior Subordinated Notes due 2014 | — | 329 |
| 6 % Senior Subordinated Notes due 2016 | 565 | 568 |
| 7 % Senior Subordinated Notes due 2018 | 636 | 635 |
| 6 % Senior Subordinated Notes due 2020 | 744 | 745 |

Amounts outstanding under our credit arrangements at June 30, 2012 and December 31, 2011 are stated at cost, which approximates fair value. Please see Note 8, “Debt.”

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

8. Debt:

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

| | June 30, 2012 | December 31, 2011 |
|---|---|---|
| | (In millions) | |
| Senior unsecured debt: | | |
| Revolving credit facility LIBOR based loans | $ — | $ 85 |
| Money market lines of credit(1) | — | 1 |
| Total credit arrangements | — | 86 |
| 5¾% Senior Notes due 2022 | 750 | 750 |
| 5 % Senior Notes due 2024 | 1,000 | — |
| Total senior unsecured debt | 1,750 | 836 |
| 6 % Senior Subordinated Notes due 2014 | — | 325 |
| 6 % Senior Subordinated Notes due 2016 | 550 | 550 |
| 7 % Senior Subordinated Notes due 2018 | 600 | 600 |
| 6 % Senior Subordinated Notes due 2020 | 695 | 695 |
| Total long-term debt | $ 3,595 | $ 3,006 |

(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

We have a revolving credit facility that matures in June 2016. The terms of the credit facility provide for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, N.A., as agent. In September 2011, we entered into the first amendment to the credit facility, which allows us to issue senior notes or other debt instruments that are secured equally and ratably with the credit facility. As of June 30, 2012, the largest individual loan commitment by any lender was 13% 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, 2012) 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, 2012).

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, 2012). We incurred aggregate commitment fees under our current credit facility of approximately $0.6 million and $1.6 million for the three and six months ended June 30, 2012, respectively, which are recorded in "Interest expense" on our consolidated statement of net income. For the three and six months ended June 30, 2011, we incurred commitment fees under our current and previous credit facility of approximately $0.4 million and $0.8 million, respectively.

Our credit facility has restrictive covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 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, 2012, we were in compliance with all of our debt covenants.

Letters of credit are subject to a fronting fee of 20 basis points and annual fees based on a grid of our debt rating (175 basis points at June 30, 2012). As of June 30, 2012, we had no letters of credit outstanding under our credit facility.

Subject to compliance with the restrictive covenants in our credit facility, we also have a total of $185 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions.

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.

Senior and Senior Subordinated Notes

In September 2011, we issued $750 million of 5¾% Senior Notes due 2022 and received proceeds of $742 million (net of discount and offering costs). These notes were issued at 99.956% of par to yield 5¾%. We used the net proceeds to repay a portion of our then outstanding borrowings under our credit facility and money market lines of credit.

On April 30, 2012, we redeemed our $325 million aggregate principal of 6 % Senior Subordinated Notes due 2014 at 101.1042% of the principal amount plus accrued interest, which included the payment of an early redemption premium of $4 million. This premium was recorded under the caption "Other income (expenses) – Other" on our consolidated statement of net income. The repayment of the outstanding principal balance of $325 million was funded through the use of our revolving credit facility.

On June 26, 2012, we issued $1 billion of 5 % Senior Notes due 2024 and received proceeds of $990 million (net of offering costs of approximately $10 million). These notes were issued at par to yield 5 %. We used a portion of the net proceeds to repay borrowings outstanding under our credit facility and money market lines of credit. Simultaneous to the notes offering, we initiated a tender offer and consent solicitation for our outstanding 6 % Senior Subordinated Notes due 2016. See Note 14, "Subsequent Events."

9. Income Taxes:

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In millions) | | | |
| Amount computed using the statutory rate | $ 75 | $ 121 | $ 140 | $ 112 |
| Increase in taxes resulting from: | | | | |
| State and local income taxes, net of federal effect | 1 | 7 | 3 | 5 |
| Net effect of different tax rates in non-U.S. jurisdictions | 3 | — | 7 | 1 |
| Total provision for income taxes | $ 79 | $ 128 | $ 150 | $ 118 |

As of June 30, 2012, we did not have a liability for uncertain tax positions and as such we had not accrued related interest or penalties. The tax years 2008-2011 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which we are subject.

10. Stock-Based Compensation:

All stock-based compensation equity awards to employees and non-employee directors are granted currently 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 February 2011, we also granted cash-settled restricted stock units to employees that were not issued under any of our plans as they will be settled in cash upon vesting and are accounted for as liability awards.

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

| | Three Months Ended June 30, 2012 | Three Months Ended June 30, 2011 | Six Months Ended June 30, 2012 | Six Months Ended June 30, 2011 |
|---|---|---|---|---|
| | (In millions) | | | |
| Total stock-based compensation | $ 12 | $ 11 | $ 24 | $ 19 |
| Capitalized in oil and gas properties | (3) | (3) | (7) | (5) |
| Net stock-based compensation expense | $ 9 | $ 8 | $ 17 | $ 14 |

As of June 30, 2012, we had approximately $104 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 five years.

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Stock Options. The following table provides information about stock option activity for the six months ended June 30, 2012:

| | Number of Shares Underlying Options (In millions) | Weighted-Average Exercise Price per Share | Weighted-Average Grant Date Fair Value per Share | Weighted-Average Remaining Contractual Life (In years) | Aggregate Intrinsic Value(1) (In millions) |
|---|---|---|---|---|---|
| Outstanding at December 31, 2011 | 1.1 | $36.31 | | 4.0 | $7 |
| Granted | — | — | $— | | |
| Exercised/Forfeited | — | — | | | |
| Outstanding at June 30, 2012 | 1.1 | $36.77 | | 3.6 | $2 |
| | | | | | |
| Exercisable at June 30, 2012 | 0.9 | $35.86 | | 3.4 | $2 |

(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, 2012, the last reported sales price of our common stock on the New York Stock Exchange was $29.31 per share.

Restricted Stock. The following table provides information about restricted stock and restricted stock unit activity for the six months ended June 30, 2012:

| | Service-Based Shares | Performance/ Market-Based Shares | Total Shares | Weighted-Average Grant Date Fair Value per Share |
|---|---|---|---|---|
| | (In millions, except per share data) | | | |
| Non-vested shares outstanding at December 31, 2011 | 2.2 | 0.3 | 2.5 | $49.52 |
| Granted | 1.3 | 0.2 | 1.5 | 36.46 |
| Forfeited | (0.2) | — | (0.2) | 47.64 |
| Vested | (0.6) | (0.1) | (0.7) | 39.96 |
| Non-vested shares outstanding at June 30, 2012 | 2.7 | 0.4 | 3.1 | $45.51 |

Cash-Settled Restricted Stock Units. During the first quarter of 2011, we granted cash-settled restricted stock units to 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 units for approximately $1.7 million. As of June 30, 2012, approximately 79,000 cash-settled restricted units were outstanding.

Employee Stock Purchase Plan. Pursuant to our employee stock purchase plan, for each six-month period beginning on January 1 or July 1 during the term of the plan, each eligible employee has the opportunity to purchase our common stock for a purchase price equal to 85% of the lesser of the fair market value of our common stock on the first day of the period or the last day of the period.

During the first six months of 2012, options to purchase approximately 87,000 shares of our common stock were issued under our employee stock purchase plan. The weighted-average fair value of each option was $11.61 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 0.06%, an expected life of six months and weighted-average volatility of 55%.

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

11. 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 position, cash flows or results of operations.

12. Segment Information:

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

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

The following tables provide the geographic operating segment information for the three and six months ended June 30, 2012 and 2011. Income tax allocations have been determined based on statutory rates in the applicable geographic segment.

Three Months Ended June 30, 2012:

| | Domestic | Malaysia | China | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| Oil and gas revenues | $ 351 | $ 247 | $ 30 | $ 628 |
| | | | | |
| Operating expenses: | | | | |
| Lease operating | 104 | 23 | 2 | 129 |
| Production and other taxes | 15 | 68 | 5 | 88 |
| Depreciation, depletion and amortization | 172 | 60 | 7 | 239 |
| General and administrative | 60 | 1 | — | 61 |
| Allocated income tax | 1 | 36 | 4 | |
| Net income (loss) from oil and gas properties | $ (1 ) | $ 59 | $ 12 | |
| | | | | |
| Total operating expenses | | | | 517 |
| Income from operations | | | | 111 |
| Interest expense, net of interest income, | | | | |
| capitalized interest and other | | | | (32 ) |
| Commodity derivative income | | | | 135 |
| Income before income taxes | | | | $ 214 |
| | | | | |
| Total assets | $ 8,692 | $ 853 | $ 299 | $ 9,844 |
| | | | | |
| Additions to long-lived assets | $ 408 | $ 38 | $ 5 | $ 451 |

Three Months Ended June 30, 2011:

| | Domestic | Malaysia | China | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| Oil and gas revenues | $475 | $123 | $23 | $621 |
| | | | | |
| Operating expenses: | | | | |
| Lease operating | 90 | 33 | 2 | 125 |
| Production and other taxes | 22 | 51 | 6 | 79 |
| Depreciation, depletion and amortization | 149 | 19 | 5 | 173 |
| General and administrative | 43 | 1 | — | 44 |
| Allocated income tax | 64 | 7 | 2 | |
| Net income from oil and gas properties | $107 | $12 | $8 | |
| | | | | |
| Total operating expenses | | | | 421 |
| Income from operations | | | | 200 |

| | | | | |
|---|---|---|---|---|
| Interest expense, net of interest income, | | | | |
| capitalized interest and other | | | | (22) |
| Commodity derivative income | | | | 169 |
| Income before income taxes | | | | $347 |
| | | | | |
| Total assets | $7,480 | $772 | $229 | $8,481 |
| | | | | |
| Additions to long-lived assets | $836 | $86 | $25 | $947 |

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

Six Months Ended June 30, 2012:

| | Domestic | Malaysia | China | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| Oil and gas revenues | $753 | $496 | $57 | $1,306 |
| | | | | |
| Operating expenses: | | | | |
| Lease operating | 206 | 46 | 4 | 256 |
| Production and other taxes | 36 | 123 | 12 | 171 |
| Depreciation, depletion and amortization | 338 | 114 | 13 | 465 |
| General and administrative | 104 | 2 | — | 106 |
| Allocated income tax | 26 | 80 | 7 | |
| Net income from oil and gas properties | $43 | $131 | $21 | |
| | | | | |
| Total operating expenses | | | | 998 |
| Income from operations | | | | 308 |
| Interest expense, net of interest income, capitalized interest and other | | | | (66) |
| Commodity derivative income | | | | 159 |
| Income before income taxes | | | | $401 |
| | | | | |
| Total assets | $8,692 | $853 | $299 | $9,844 |
| | | | | |
| Additions to long-lived assets | $884 | $69 | $20 | $973 |

Six Months Ended June 30, 2011:

| | Domestic | Malaysia | China | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| Oil and gas revenues | $869 | $257 | $40 | $1,166 |
| | | | | |
| Operating expenses: | | | | |
| Lease operating | 167 | 48 | 3 | 218 |
| Production and other taxes | 37 | 102 | 11 | 150 |
| Depreciation, depletion and amortization | 286 | 44 | 9 | 339 |
| General and administrative | 79 | 2 | — | 81 |
| Allocated income taxes | 111 | 23 | 4 | |
| Net income from oil and gas properties | $189 | $38 | $13 | |
| | | | | |
| Total operating expenses | | | | 788 |
| Income from operations | | | | 378 |
| Interest expense, net of interest income, capitalized interest and other | | | | (45) |
| Commodity derivative expense | | | | (13) |
| Income before income taxes | | | | $320 |

| | | | | |
|---|---|---|---|---|
| Total assets | $7,480 | $772 | $229 | $8,481 |
| Additions to long-lived assets | $1,261 | $127 | $35 | $1,423 |

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

13. Supplemental Cash Flows Information:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In millions) | | | |
| Non-cash items excluded from the statement of cash flows: | | | | |
| Increase in accrued capital expenditures | $(23) | $(7) | $(66) | $(10) |
| Increase in asset retirement costs | (9) | (6) | (5) | (8) |

14. Subsequent Events:

In July 2012, we completed the tender and redemption of our $550 million aggregate principal of 6  % Senior Subordinated Notes due 2016. The transactions included a premium payment of approximately $14 million.

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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 onshore Texas. Internationally, we focus on offshore oil developments in Malaysia and China.

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

We prepare our financial statements in conformity with generally accepted accounting principles, which requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved oil and gas reserves. 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". The risk of incurring a ceiling test writedown increases when commodity prices are low for a sustained period of time. If we assume the unweighted average first-date-of-the-month commodity prices for the remainder of 2012 were the same as July 2012 commodity prices of $2.74 per MMBtu for natural gas and $84.80 per barrel of oil, adjusted for market differentials, which were approximately 12% lower than the unweighted average first-day-of-the-month commodity prices for the prior 12 months, we would not anticipate a ceiling test writedown during 2012. However, if there are further declines in the 12-month unweighted average commodity prices, we may be required to record a ceiling test writedown in future periods.

Operational Highlights. Significant operational highlights during the second quarter of 2012 include the following:

- Total production for the second quarter of 2012, including natural gas produced and consumed in operations, was 76.4 Bcfe, an increase of 4% over second quarter 2011 production volumes.
- Oil and liquids liftings in the second quarter of 2012 were approximately 6.1 million barrels, or an average of approximately 67,000 BOPD, which is approximately 2,000 BOPD higher than the first quarter of 2012 and approximately 40% higher than the second quarter of 2011.
- Our assessment program on more than 135,000 net acres in the Cana Woodford has delivered six successful appraisal wells in our Mid-Continent division.
- We achieved a record net production rate of 25,000 BOPD in the Uinta Basin of our Rocky Mountain division.
- 

We drilled three successful “super extended lateral” wells in the Eagle Ford Shale of our Onshore Gulf Coast division and additional drilling is planned for 2012.

• Our six most recent completions in the Williston Basin (average 11,000’ laterals) have contributed to a new high in Williston Basin net production of 10,000 BOEPD.

• We achieved a record net production rate of 16,500 BOEPD at East Belumut/Chermingat, offshore Malaysia. Current net production in Malaysia is more than 30,000 BOEPD.

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Financial Highlights. Significant financial highlights during the second quarter of 2012 included the following:

- Our revenues were slightly higher than the same period in 2011, driven by a 40% increase in oil and liquids volumes despite lower commodity prices.
- We issued $1 billion 5  % Senior Notes due 2024 to reduce interest costs and extend the maturities of existing Senior Subordinated Notes.
- We redeemed our $325 million 6  % Senior Subordinated Notes due 2014.
- We announced a tender offer and consent solicitation for our $550 million 6  % Senior Subordinated Notes due 2016, which was ultimately completed on July 18, 2012.

Results of Operations

Revenues. All of our revenues are derived from the sale of our oil and gas production and do not include the effects of the settlements of our hedges. Please see Note 4, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

Our revenues may vary significantly from period-to-period as a result of changes in commodity prices or volumes of production sold. In addition, substantially all of the crude oil from our operations offshore Malaysia and China is produced into FPSOs and lifted and sold periodically as barge quantities are accumulated. Revenues are recorded when oil is lifted and sold, not when it is produced into the FPSO. As a result, the timing of liftings may impact period-to-period results.

Revenues of $628 million for the second quarter of 2012 were slightly higher than the comparable period of 2011. Revenues of $1.3 billion for the first six months of 2012 were 12% higher than the comparable period of 2011. The 40% increase in oil, condensate and NGLs production during the second quarter of 2012 was offset by a slight decrease in average realized prices for all products and a 16% decrease in natural gas production as compared to the comparable period of 2011. The 37% increase in oil, condensate and NGLs production and 3% increase in average realized prices for these products for the six-month period ended June 30, 2012 was partially offset by the 14% decrease in natural gas production and a 42% decrease in average realized natural gas prices for the same period of 2011.

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The following table summarizes production and average realized prices by product and by geographic area for the three- and six-month periods ended June 30, 2012 and 2011.

| | Three Months Ended June 30, 2012 | Three Months Ended June 30, 2011 | Percentage Increase (Decrease) | Six Months Ended June 30, 2012 | Six Months Ended June 30, 2011 | Percentage Increase (Decrease) |
|---|---|---|---|---|---|---|
| Production:(1) | | | | | | |
| Domestic: | | | | | | |
| Natural gas (Bcf) | 37.8 | 45.4 | (17) % | 76.1 | 89.0 | (15) % |
| Oil, condensate and NGLs (MBbls) | 3,544 | 3,142 | 13 % | 7,141 | 6,015 | 19 % |
| Total (Bcfe) | 59.0 | 64.3 | (8) % | 118.9 | 125.1 | (5) % |
| International: | | | | | | |
| Natural gas (Bcf) | 0.2 | — | 100 % | 0.4 | — | 100 % |
| Oil, condensate and NGLs (MBbls) | 2,553 | 1,227 | 108 % | 4,859 | 2,719 | 79 % |
| Total (Bcfe) | 15.6 | 7.3 | 111 % | 29.6 | 16.3 | 81 % |
| Total: | | | | | | |
| Natural gas (Bcf) | 38.0 | 45.4 | (16) % | 76.5 | 89.0 | (14) % |
| Oil, condensate and NGLs (MBbls) | 6,097 | 4,369 | 40 % | 12,000 | 8,734 | 37 % |
| Total (Bcfe) | 74.6 | 71.6 | 4 % | 148.5 | 141.4 | 5 % |
| | | | | | | |
| Average Realized Prices:(2) | | | | | | |
| Domestic: | | | | | | |
| Natural gas (per Mcf) | $ 2.26 | $ 4.42 | (49) % | $ 2.45 | $ 4.21 | (42) % |
| Oil, condensate and NGLs (per Bbl) | 74.20 | 87.03 | (15) % | 78.88 | 81.68 | (3) % |
| Natural gas equivalent (per Mcfe) | 5.94 | 7.40 | (20) % | 6.33 | 6.95 | (9) % |
| International: | | | | | | |
| Natural gas (per Mcf) | $ 3.98 | $ — | 100 % | $ 4.15 | $ — | 100 % |
| Oil, condensate and NGLs (per Bbl) | 108.07 | 118.72 | (9) % | 113.34 | 109.12 | 4 % |
| Natural gas equivalent (per Mcfe) | 17.81 | 19.79 | (10) % | 18.68 | 18.19 | 3 % |
| Total: | | | | | | |
| Natural gas (per Mcf) | $ 2.27 | $ 4.42 | (49) % | $ 2.46 | $ 4.21 | (42) % |
| Oil, condensate and NGLs (per Bbl) | 88.39 | 95.94 | (8) % | 92.84 | 90.23 | 3 % |
| Natural gas equivalent (per Mcfe) | 8.41 | 8.68 | (3) % | 8.79 | 8.25 | 7 % |

(1) Represents volumes lifted and sold regardless of when produced. Excludes natural gas produced and consumed in our operations of 1.8 Bcfe and 1.6 Bcfe during the three months ended June 30, 2012 and 2011, respectively, and 4.0 Bcfe and 3.3 Bcfe during the six months ended June 30, 2012 and 2011, respectively.

(2)

Had we included the effects of hedging contracts not designated for hedge accounting, our average realized price for total natural gas would have been $3.65 and $5.77 per Mcf for the three months ended June 30, 2012 and 2011, respectively, and $3.67 and $5.64 per Mcf for the six months ended June 30, 2012 and 2011, respectively. Our total oil, condensate and NGLs average realized price would have been $88.35 and $91.16 per Bbl for the three months ended June 30, 2012 and 2011, respectively, and $92.23 and $86.51 per Bbl for the six months ended June 30, 2012 and 2011, respectively.

Domestic Production. Consistent with our expectations, over 80%, or 4.4 Bcfe, of the 5.3 Bcfe decrease in production for the three-month period ended June 30, 2012 as compared to the same period of 2011 was due to natural field decline, maintenance-related shut-ins and the sale of certain non-strategic assets. Decreases in natural gas production due to natural field decline and maintenance-related shut-ins were partially offset by increases in oil and liquids production in our Onshore Gulf Coast, Mid-Continent and Rocky Mountain divisions as a result of continued successful assessment and development drilling efforts.

The 6.2 Bcfe decrease for the six-month period ended June 30, 2012 as compared to the same period of 2011 was primarily related to decreased natural gas production in our Gulf of Mexico operations and Onshore Gulf Coast division primarily due to natural field decline, maintenance-related shut-ins and the sale of certain non-strategic assets. Consistent with our strategic shift to liquids, our continued successful assessment and development drilling efforts for oil and liquids in our Onshore Gulf Coast, Mid-Continent and Rocky Mountain divisions partially offset the decline in natural gas production.

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International Production. Our international oil production for the three- and six-month periods ended June 30, 2012, increased over the comparable periods of 2011 primarily as a result of liftings associated with production from our recent developments at East Piatu and Puteri brought online during the fourth quarter of 2011 and continued successful development drilling efforts in Malaysia.

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

The following table presents information about our operating expenses for the three months ended June 30, 2012 and 2011.

| | Unit-of-Production Three Months Ended June 30, 2012 | 2011 | Percentage Increase (Decrease) | Total Amount Three Months Ended June 30, 2012 | 2011 | Percentage Increase (Decrease) |
|---|---|---|---|---|---|---|
| | (Per Mcfe) | | | (In millions) | | |
| Domestic: | | | | | | |
| Lease operating | $ 1.76 | $ 1.41 | 25% | $ 104 | $ 90 | 15% |
| Production and other taxes | 0.26 | 0.34 | (24)% | 15 | 22 | (31)% |
| Depreciation, depletion and amortization | 2.91 | 2.32 | 23% | 172 | 149 | 13% |
| General and administrative | 1.00 | 0.66 | 52 % | 60 | 43 | 39% |
| Total operating expenses | 5.93 | 4.73 | 25 % | 351 | 304 | 15% |
| International: | | | | | | |
| Lease operating | $ 1.59 | $ 4.58 | (65) % | $ 25 | $ 35 | (27)% |
| Production and other taxes | 4.66 | 7.73 | (40) % | 73 | 57 | 27% |
| Depreciation, depletion and amortization | 4.34 | 3.35 | 30 % | 67 | 24 | 174% |
| General and administrative | 0.12 | 0.24 | (50) % | 1 | 1 | 9% |
| Total operating expenses | 10.70 | 15.88 | (33) % | 166 | 117 | 42% |
| Total: | | | | | | |
| Lease operating | $ 1.73 | $ 1.74 | (1) % | $ 129 | $ 125 | 3% |
| Production and other taxes | 1.17 | 1.10 | 6% | 88 | 79 | 11% |
| Depreciation, depletion and amortization | 3.20 | 2.42 | 31% | 239 | 173 | 36% |
| General and administrative | 0.82 | 0.62 | 32% | 61 | 44 | 38% |
| Total operating expenses | 6.92 | 5.88 | 18% | 517 | 421 | 23% |

Domestic Operations. Our domestic operating expenses for the three months ended June 30, 2012, stated on a Mcfe basis, increased 25% over the same period of 2011. The components of the period-to-period change are as follows:

- Lease operating expenses (LOE) include normally recurring expenses to operate and produce our oil and gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. The increase in total domestic LOE per Mcfe resulted primarily from a $12 million increase in non-recurring costs related to well workovers and repairs in our Gulf of Mexico deepwater operations and Rocky Mountain division, which together accounted for 88% ($0.20 per Mcfe) of the total increase in domestic LOE.

- Production and other taxes per Mcfe decreased primarily due to a 20% decrease in average realized prices, as compared to the same period of 2011.

- Since late 2009, the continued shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our depreciation, depletion and amortization (DD&A) rate, resulting in the increase in DD&A expense.

- General and administrative (G&A) expense per Mcfe increased primarily due to employee-related expenses associated with our growing domestic work force. We capitalized $24 million ($0.40 per Mcfe) and $19 million ($0.30 per Mcfe) of direct internal costs during the second quarters of 2012 and 2011, respectively.

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International Operations. Our international operating expenses for the three months ended June 30, 2012, stated on a Mcfe basis, decreased 33% as compared to the same period of 2011. The components of the period-to-period change are as follows:

- LOE per Mcfe decreased primarily due to an overall change in the mix of production that was lifted and sold from the various production sharing contracts (PSCs) during the second quarter of 2012 resulting from new production from two developments (East Piatu and Puteri), which commenced production during the fourth quarter of 2011 and continued successful development drilling efforts in Malaysia.

- Production and other taxes per Mcfe decreased due to an overall change in the mix of production that was lifted and sold from the various PSCs in Malaysia as stated above and due to lower average realized oil prices during the second quarter of 2012. In addition, the tax rate per barrel of oil lifted and sold from these developments is lower, per the terms of our PSCs, while we recover our costs associated with these developments.

The following table presents information about our operating expenses for the six months ended June 30, 2012 and 2011.

| | Unit-of-Production Six Months Ended June 30, 2012 (Per Mcfe) | Unit-of-Production Six Months Ended June 30, 2011 (Per Mcfe) | Percentage Increase (Decrease) | Total Amount Six Months Ended June 30, 2012 (In millions) | Total Amount Six Months Ended June 30, 2011 (In millions) | Percentage Increase (Decrease) |
|---|---|---|---|---|---|---|
| Domestic: | | | | | | |
| Lease operating | $ 1.73 | $ 1.34 | 29 % | $ 206 | $ 167 | 23 % |
| Production and other taxes | 0.30 | 0.30 | — | 36 | 37 | (4) % |
| Depreciation, depletion and amortization | 2.84 | 2.29 | 23 % | 338 | 286 | 17 % |
| General and administrative | 0.87 | 0.63 | 38 % | 104 | 79 | 31 % |
| Total operating expenses | 5.75 | 4.56 | 26 % | 684 | 569 | 20 % |
| International: | | | | | | |
| Lease operating | $ 1.67 | $ 3.10 | (46) % | $ 50 | $ 51 | (2) % |
| Production and other taxes | 4.56 | 6.89 | (34) % | 135 | 113 | 20 % |
| Depreciation, depletion and amortization | 4.32 | 3.26 | 33 % | 127 | 53 | 140 % |
| General and administrative | 0.08 | 0.15 | (47) % | 2 | 2 | — % |
| Total operating expenses | 10.63 | 13.40 | (21) % | 314 | 219 | 44 % |
| Total: | | | | | | |
| Lease operating | $ 1.72 | $ 1.54 | 12 % | $ 256 | $ 218 | 17 % |
| Production and other taxes | 1.15 | 1.06 | 8 % | 171 | 150 | 14 % |
| Depreciation, depletion and amortization | 3.13 | 2.40 | 30 % | 465 | 339 | 36 % |
| | 0.71 | 0.58 | 22 % | 106 | 81 | 31 % |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| General and administrative | | | | | | | | |
| Total operating expenses | 6.72 | 5.58 | 20 | % | 998 | 788 | 27 | % |

Domestic Operations. Our domestic operating expenses for the six months ended June 30, 2012, stated on a Mcfe basis, increased 26% over the same period of 2011. The components of the period-to-period change are as follows:

- LOE includes normally recurring expenses to operate and produce our oil and gas wells, non-recurring well workover and repair-related expenses and the costs to transport our production to the applicable sales points. Recurring LOE in our Rocky Mountain division accounted for approximately 44% ($0.14 per Mcfe) of the increase due to increased operations and service-related costs in the basins in which we operate. Non-recurring costs related to well workovers and repairs in our Gulf of Mexico deepwater operations and Rocky Mountain division together accounted for an additional 47% ($0.15 per Mcfe) of the total increase in domestic LOE.

- Since late 2009, the continued shift of our capital investments toward the oil plays in our portfolio has resulted in an increase in our DD&A rate, resulting in the increase in DD&A expense.

- G&A expense per Mcfe increased primarily due to employee-related expenses associated with our growing domestic work force. During the six months ended June 30, 2012, we capitalized $47 million ($0.40 per Mcfe), as compared to $38 million ($0.30 per Mcfe) during the same period of 2011.

International Operations. Our international operating expenses for the six months ended June 30, 2012, stated on a Mcfe basis, decreased 21% as compared to the same period of 2011. The components of the period-to-period change are as follows:

- LOE per Mcfe decreased primarily due to an overall change in the mix of production that was lifted and sold from the various PSCs in Malaysia during the first six months of 2012 resulting from new production from two developments (East Piatu and Puteri), which commenced production during the fourth quarter of 2011 and continued successful development drilling efforts.

- Production and other taxes per Mcfe decreased due to an overall change in the mix of production that was lifted and sold from the various PSCs in Malaysia as stated above and due to lower average realized oil prices during the first six months of 2012. In addition, the tax rate per barrel of oil lifted and sold from these developments is lower, per the terms of our PSCs, while we recover our costs associated with these developments.

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

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| | (In millions) | | | |
| Gross interest expense: | | | | |
| Credit arrangements | $3 | $3 | $5 | $4 |
| Senior notes | 12 | — | 23 | — |
| Senior subordinated notes | 34 | 38 | 72 | 76 |
| Other | — | — | — | 1 |
| Total gross interest expense | 49 | 41 | 100 | 81 |
| Capitalized interest | (18) | (19) | (36) | (37) |
| Net interest expense | $31 | $22 | $64 | $44 |

The increase in gross interest expense for the three and six months ended June 30, 2012, as compared to the same periods of 2011, primarily resulted from the September 2011 issuance of $750 million aggregate principal amount of 5¾% Senior Notes due 2022. See Note 8, "Debt," to our consolidated financial statements appearing earlier in this report. Interest expense related to unproved properties is capitalized into oil and gas properties.

Taxes. Our effective tax rate generally approximates 37% and specifically was 37% for the second quarters and first six months of 2012 and 2011. Our effective tax rate for all periods was different than the federal statutory tax rate due to deductions that do not generate tax benefits, state income taxes and the differences between international and U.S. federal statutory rates.

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

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Liquidity and Capital Resources

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

We establish a capital budget at the beginning of each calendar year 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, primarily cash flows from operations. Approximately 90% of our expected 2012 domestic oil and gas production (excluding NGLs) supporting the current 2012 capital budget is hedged. Our 2012 capital budget, excluding capitalized interest and overhead of $210 million, is approximately $1.7 billion and focuses on projects with expected higher returns and that we believe will generate and lay the foundation for oil production growth in 2012 and thereafter. Substantially all of the 2012 budget is allocated to oil or liquids-rich projects.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results, oil and natural gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We believe we have the operational flexibility to react quickly with our capital expenditures to changes in circumstances and our cash flows from operations.

During the first six months of 2012, we received proceeds from the sale of certain non-strategic assets of $329 million, redeemed our $325 million aggregate principal of 6 % Senior Subordinated Notes due 2014, announced a cash tender offer and solicitation for any, and all, of our $550 million aggregate principal of 6 % Senior Subordinated Notes due 2016 and issued $1 billion aggregate principal of 5 % Senior Notes due 2024. We used a portion of the proceeds from the $1 billion Senior Notes offering combined with the proceeds from our non-strategic asset sale program to eliminate borrowings outstanding under our credit arrangements, and as a result, at June 30, 2012, we had available borrowing capacity of $1.4 billion under our credit arrangements. We continue to market other certain non-strategic assets. We expect to substantially fund our $1.7 billion 2012 capital program with cash flows from operations and the proceeds from non-strategic asset sales during the year. We believe that the Company’s liquidity position and our ability to generate cash flows from our asset portfolio will be adequate to fund current and long-term operations.

Credit Arrangements. We have a revolving credit facility that matures in June 2016 and provides for loan commitments of $1.25 billion from a syndicate of 13 financial institutions, led by JPMorgan Chase Bank, N.A., as agent. As of June 30, 2012, the largest individual commitment by any lender was 13% of total commitments.

In addition, subject to compliance with restrictive covenants in our credit facility, we also have a total of $185 million of borrowing capacity under money market lines of credit with various financial institutions, the availability of which is at the discretion of the financial institutions. For a more detailed description of the terms of our credit arrangements, please see Note 8, “Debt,” to our consolidated financial statements appearing earlier in this report.

As of July 23, 2012, we had $14.5 million of letters of credit outstanding under our credit facility. In addition, we had no outstanding borrowings under either our credit facility or our money market lines of credit. Our available borrowing capacity under our credit arrangements was approximately $1.4 billion as of July 23, 2012.

Senior and Senior Subordinated Notes. On April 30, 2012, we redeemed our $325 million aggregate principal of 6 % Senior Subordinated Notes due 2014 at 101.1042% of the principal amount plus accrued interest, which included the payment of an early redemption premium of $4 million. This premium was recorded under the caption “Other income (expenses) – Other” on our consolidated statement of net income. The repayment of the outstanding principal balance of $325 million was funded through the use of our revolving credit facility.

On June 26, 2012, we issued $1 billion of 5 % Senior Notes due 2024 and received proceeds of $990 million (net of offering costs of approximately $10 million). These notes were issued at par to yield 5 %. We used a portion of the net proceeds to repay borrowings outstanding under our credit facility and money market lines of credit. Simultaneous to the notes offering, we initiated a tender offer and consent solicitation for our outstanding 6 % Senior Subordinated Notes due 2016, which was completed on July 18, 2012.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. Although we anticipate that our 2012 capital spending (excluding acquisitions) will correspond with our anticipated 2012 cash flows from operations and property sales proceeds, we may borrow and repay funds under our credit arrangements throughout the year since the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

At June 30, 2012, we had positive working capital of $532 million compared to negative working capital of $157 million at December 31, 2011. The changes in our working capital are primarily a result of the unused proceeds of our $1 billion Senior Notes due 2024 and the timing of the collection of receivables, drilling activities, payments made by us to vendors and other operators and the timing and amount of advances received from our joint operations.

Cash Flows from Operations. Cash flows from operations are our primary source of capital and liquidity, and are primarily affected by production and commodity prices, net of the effects of settlements of our derivative contracts and changes in working capital. We sell substantially all of our oil and gas production under floating price, market sensitive contracts. We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months. See "—Oil and Gas Hedging" below.

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

Our net cash flows from operations were $575 million for the six months ended June 30, 2012, a decrease of $154 million compared to net cash flows from operations of $729 million for the same period in 2011, primarily due to working capital changes. Our working capital requirements change each period as a result of the timing of drilling activities, receivable collections from purchasers and joint interest partners, payments made by us to vendors and other operators, the timing and amount of advances received from our joint operations and the change in net cash receipts on derivative settlements.

Cash Flows from Investing Activities. Net cash used in investing activities for the six months ended June 30, 2012 was $568 million compared to $1.3 billion for the same period in 2011.

During the six months ended June 30, 2012, we:

- spent approximately $900 million (including $9 million for acquisitions of oil and gas properties); and
- received proceeds of $329 million from sales of oil and gas properties.

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

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

redeemed investments of $1 million.

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Cash Flows from Financing Activities. Net cash flows provided by financing activities for the six months ended June 30, 2012 and 2011 were $573 million.

During the six months ended June 30, 2012, we:

- borrowed and repaid $1.7 billion under our credit arrangements;
- issued $1 billion aggregate principal amount of 5 % Senior Notes due 2024 at par and paid approximately $10 million in associated debt issue costs;
- repaid our $325 million aggregate principal amount of 6 % Senior Subordinated Notes due 2014; and
- repurchased $7 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

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

- borrowed $2.4 billion and repaid $1.8 billion under our credit arrangements;
- paid $8 million in debt issue costs associated with our new credit facility;
- received proceeds of $11 million from the issuance of shares of our common stock upon the exercise of stock options; and
- repurchased $17 million of our common stock surrendered by employees to pay tax withholding upon the vesting of restricted stock and restricted stock unit awards.

Capital Expenditures. Our capital investments of $1.0 billion for the first six months of 2012 decreased 13% from our capital investments of $1.1 billion during the same period of 2011. These amounts exclude acquisitions for the first six months of 2012, which were immaterial, and $310 million during the same period of 2011 and recorded asset retirement obligations of $5 million and $8 million in the respective periods. Of the total $1.0 billion spent during the first six months of 2012, we invested $725 million in domestic exploitation and development, $102 million in domestic exploration (exclusive of exploitation and leasehold activity), $44 million in leasing domestic proved and unproved property (leasehold) and $86 million outside the United States. Of the total $1.1 billion spent during the first six months of 2011, we invested $750 million in domestic exploitation and development, $114 million in domestic exploration (exclusive of exploitation and leasehold activity), $76 million in leasing domestic proved and unproved property (leasehold) and $155 million outside the United States.

We have budgeted approximately $1.7 billion for capital spending in 2012. The planned budget excludes capitalized interest and overhead of $210 million and acquisitions. Substantially all of the 2012 budget is allocated to oil or liquids-rich projects. Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, oil and natural gas prices, industry conditions, the prices and availability of goods and services and the extent to which properties are acquired.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. For further information, please 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, 2011. Significant changes in our contractual obligations during 2012 include the following:

- In January 2012, we executed an agreement to provide 20,000 barrels of oil per day (approximately 7,300 MBbls per year) of refining capacity that spans a ten-year period with commitments commencing in January 2014.
- In April 2012, we redeemed our $325 million aggregate principal of 6  % Senior Subordinated Notes due 2014 at 101.1042% of the principal amount plus accrued interest. This terminates the related semi-annual interest payments of approximately $11 million that were scheduled through September 2014.
- In June 2012, we issued $1 billion of 5  % Senior Notes due 2024. These notes were issued at par to yield 5  %. The semi-annual interest payments of approximately $28 million associated with these notes are scheduled to commence in January 2013.

- In July 2012, we completed the tender and redemption of our $550 million aggregate principal of 6 % Senior Subordinated Notes due 2016. This terminates the related semi-annual interest payments of approximately $18 million that were scheduled through April 2016.

Oil and Gas Hedging

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

While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future 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 will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty, and we have netting arrangements with all of our counterparties that provide for offsetting payables against receivables from separate hedging arrangements with that counterparty. At June 30, 2012, Bank of Montreal, Barclays Bank PLC, J Aron & Company, JPMorgan Chase Bank, N.A., Macquarie Bank Limited, and Morgan Stanley Capital Group Inc. were the counterparties with respect to approximately 85% of our estimated future hedged production, the largest of which was J Aron & Company, which accounted for 25% of our estimated future hedged production.

The counterparties to the majority of our derivative instruments also are lenders under our credit facility. 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.

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

The price that we receive for natural gas production from the Gulf of Mexico and onshore Gulf Coast, after basis differentials, transportation and handling charges, typically averages $0.25-$0.50 per MMBtu less than the Henry Hub Index. Realized natural gas prices for our Mid-Continent properties, after basis differentials, transportation and handling charges, typically average 94-98% of the Henry Hub Index. In the Rocky Mountains, we hedged basis associated with approximately 2 Bcf of our natural gas production from July 2012 through December 2012 to lock in the differential at a weighted average of $0.91 per MMBtu less than the Henry Hub Index. In total, this hedge and the 8,000 MMBtus per day we have sold on a fixed physical basis for the same period results in an average basis hedge of $0.91 per MMBtu less than the Henry Hub Index. In the Mid-Continent, we have hedged basis associated with approximately 9 Bcf of our anticipated natural gas production from the Stiles/Britt Ranch area for the period July 2012 through December 2012 at an average of $0.55 per MMBtu less than the Henry Hub Index.

The price we receive for our Gulf Coast oil production, excluding NGLs, typically averages about 95-100% of the NYMEX West Texas Intermediate (WTI) price. The price we receive for our oil production in the Rocky Mountains, excluding NGLs, is currently averaging about $16-$18 per barrel below the WTI price. Oil production from our Mid-Continent properties, excluding NGLs, typically averages 90-95% of the WTI price. Crude oil from our operations in Malaysia typically sells at a slight discount to Tapis, or about 110-115% of WTI. Crude oil from our operations in China typically sells at $10-$15 per barrel greater than the WTI price.

Please see the discussion and tables in Note 4, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report for a description of the accounting applicable to our hedging program, a listing of open contracts as of June 30, 2012 and the estimated fair market value of those contracts as of that date.

Accounting for Hedging Activities. We do not designate price risk management activities as accounting hedges. Because hedges not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience, significant non-cash volatility in our reported earnings during periods of commodity price volatility. As of June 30, 2012, we had net derivative assets of $210 million, of which 88% was measured based upon our valuation model (i.e. Black-Scholes) and, as such, is classified as a Level 3 fair value measurement. We value these contracts using a model that considers various inputs including (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, (d) counterparty credit risk and (e) current market and contractual prices for the underlying instruments. As a result, the value of these contracts at their respective settlement dates could be significantly different than the fair value as of June 30, 2012. We utilize credit default swap values to assess the impact of non-performance risk when evaluating both our liabilities to and receivables from counterparties. Please see "— Critical Accounting Policies and Estimates — Commodity Derivative Activities" in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2011 and Note 4, "Derivative Financial Instruments," and Note 7, "Fair Value Measurements," to our consolidated financial statements appearing earlier in this report for a discussion of the accounting applicable to our oil and gas derivative contracts.

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Other Factors. Please see “Risk Factors” in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2011 for a discussion of other factors that affect our business, financial condition and results of operations. This report should be read together with those discussions. In addition, please see “Risk Factors” in Item 1A of this report for a discussion of additional factors.

New Accounting Requirements

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

In December 2011, the FASB issued guidance regarding the disclosure of offsetting assets and liabilities. The guidance will require disclosure of gross information 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 do not expect adoption of the additional disclosures regarding offsetting assets and liabilities to have a material impact on our financial position or results of operations.

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Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results, such as planned capital expenditures, the availability and sources of capital resources to fund capital expenditures and other plans and objectives for future operations. Forward-looking information is typically identified by use of terms such as "may," "believe," "expect," "anticipate," "intend," "estimate," "project," "target," "goal," "plan," "should," "will," "predict," " 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 and natural gas 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;
- the impact of regulatory approvals;
- the availability of the securities, capital or credit markets and the cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;
- the availability of 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;
- competitive conditions;
- 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;
- 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; and
- the additional factors discussed elsewhere in our other public filings and press releases, including the factors discussed in "Risk Factors" and "Managment's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" are included in our 2011 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.

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Commonly Used Oil and Gas Terms

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

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

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

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

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

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

MMBtu. One million Btus.

MMMBtu. One billion Btus.

NGL. Natural gas liquid.

NYMEX. The New York Mercantile Exchange.

NYMEX Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

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## Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

### Oil and Natural Gas Prices

As part of our risk management program, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12-24 months to reduce our exposure to fluctuations in oil and natural gas prices. In the case of significant acquisitions, we may hedge acquired production for a longer period. In addition, we may utilize basis contracts to hedge the differential between NYMEX Henry Hub posted prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital programs and helps us manage returns on some of our acquisitions and more price sensitive drilling programs. Our decision on the quantity and price at which we choose to hedge our 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. For a further discussion of our hedging activities, see the information under the caption “Oil and Gas Hedging” in Item 2 of this report and the discussion and tables in Note 4, “Derivative Financial Instruments,” to our consolidated financial statements appearing earlier in this report.

### Interest Rates

At June 30, 2012, our debt was comprised of:

| | Fixed Rate Debt | Variable Rate Debt |
|---|---|---|
| | (In millions) | |
| 5¾% Senior Notes due 2022 | $750 | $— |
| 5 % Senior Notes due 2024 | 1,000 | — |
| 6 % Senior Subordinated Notes due 2016 | 550 | — |
| 7 % Senior Subordinated Notes due 2018 | 600 | — |
| 6 % Senior Subordinated Notes due 2020 | 695 | — |
| Total debt | $3,595 | $— |

We consider our interest rate exposure to be minimal because 100% of our obligations were at fixed rates as of June 30, 2012.

### 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 relating to foreign currencies at June 30, 2012.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2012.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the second quarter of 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. Legal Proceedings

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, or 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.

Item 1A. Risk Factors

The following risk factors update, and should be considered in addition to, the risk factors previously reported in our Annual Report on Form 10-K for the year ended December 31, 2011.

Federal legislation regarding derivatives could have an adverse effect on our ability and cost of entering into derivative transactions.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Reform Act), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. On October 1, 2010, the CFTC introduced its first series of proposed rules coming out of the Dodd-Frank Reform Act. In July 2011, the CFTC granted temporary exemptive relief from certain swap regulation provisions of the legislation until December 31, 2011, or until the agency finalized the corresponding rules. In December 2011, the CFTC extended the potential latest expiration date of the exemptive relief to July 16, 2012. In May 2012, the CFTC proposed an amendment to further extend the potential latest expiration date until December 31, 2012.

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In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. The CFTC has also issued final rules further defining "swap dealer" and "major swap participant." It is not possible at this time to predict when the CFTC will finalize other regulations, including critical rulemaking on the definition of "swap." Depending on our classification under the regulations, the financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities. The financial reform legislation may also require our counterparties to the derivative contracts to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our potential exposure to less creditworthy counterparties. If we reduce our use of derivatives or commodity prices decline as a result of the legislation and regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures, our results of operations, or our cash flows.

The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic-fracturing techniques on almost all of our U.S. onshore oil and natural gas properties, including our unconventional resource plays in the Woodford Shale of Oklahoma, the Granite Wash of Texas and Oklahoma, the Uinta Basin of Utah and the Eagle Ford and Pearsall shales of southwest Texas, which represented approximately 82% of our proved reserves and approximately 89% of our probable reserves at year-end 2011. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the Bureau of Land Management (BLM) and other federal regulatory agencies have taken steps to impose federal regulatory requirements. Certain states in which we operate, including Colorado, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic fracturing process, and the RCT adopted rules regarding the same in December 2011. In the past three years, news reports indicate that 23 states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

Notwithstanding state regulatory requirements relating to hydraulic fracturing, there are steps by federal governmental agencies that are either underway or are being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and recently released draft permitting guidance for hydraulic fracturing activities using diesel. Further, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. In addition, on May 11, 2012, the BLM issued a proposed rule that that would require the public disclosure of chemicals used in hydraulic fracturing operations, set requirements for well-bore integrity and establish flowback water standards for all hydraulic fracturing operations on federal public lands and American Indian Tribal lands. The proposed rule also requires that an operator certify, in writing, that (a) the stimulation design complies with all federal, state, tribal and local regulations; (b) the stimulation was completed in accordance with the design approved by BLM and all applicable regulations; and (c) the well-bore integrity was maintained during the fracturing process and flowback water was properly stored, treated and disposed.

Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. In a November 18, 2011 report, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued 20 recommendations to federal agencies, states, and private entities that are intended to reduce the environmental impact and assure the safety of shale gas production.

Given the heightened awareness regarding the use of hydraulic fracturing, it is possible that regulatory agencies or private parties may suggest that hydraulic fracturing has caused groundwater contamination, whether or not such allegations are accurate. For example, on December 8, 2011, the EPA released a preliminary report indicating that hydraulic fracturing is responsible for groundwater contamination in Pavillion, Wyoming, although the EPA's draft report has been hotly criticized as ignoring certain facts and utilizing incorrect data. In addition, the EPA has alleged in an enforcement action against an operator in Texas that the operator contaminated local groundwater wells, although the RCT found after an evidentiary hearing that the operator was not responsible for the contamination. Thus, regulatory agencies or private parties alleging groundwater contamination linked to hydraulic fracturing could trigger defense costs in administrative or civil litigation to rebut the allegations.

Additionally, certain members of the Congress have called upon (a) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, (b) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and (c) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanism.

Further, on April 17, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA finalized rules under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA regulations include NSPS standards for completions of hydraulically-fractured gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions. After January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAPS include specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. We are currently evaluating the effect these regulations could have on our business. Compliance with such regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Based on the foregoing, increased regulation and attention given to the hydraulic-fracturing process from federal agencies, various states and local governments could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic-fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

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

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended June 30, 2012.

| 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, 2012 | 1,350 | $ | 34.51 | — | — |
| May 1 - May 31, 2012 | 11,689 | | 34.19 | — | — |
| June 1 - June 30, 2012 | 4,801 | | 28.70 | — | — |
| Total | 17,840 | $ | 32.74 | — | — |

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

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Item 6. Exhibits

| Exhibit Number | Description |
|---|---|
| 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 February 6, 2009 (File No. 1-12534)) |
| 4.1 | Third Supplemental Indenture, dated as of June 26, 2012, between the Company and U.S. Bank National Association (as successor to Wachovia Bank, National Association (formerly First Union National Bank)), as Trustee (incorporated by reference to Exhibit 4.2 to Newfield's Current Report on Form 8-K filed with the SEC on June 26, 2012 (File No. 1-12534)) |
| *31.1 | Certification of Chief Executive Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| *31.2 | Certification of Chief Financial Officer of Newfield pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| *32.1 | Certification of Chief Executive Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| *32.2 | Certification of Chief Financial Officer of Newfield pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| *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.

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## SIGNATURE

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

NEWFIELD EXPLORATION COMPANY

| | | |
|---|---|---|
| Date: July 26, 2012 | By: | /s/ TERRY W. RATHERT |
| | | Terry W. Rathert |
| | | Executive Vice President and Chief Financial Officer |
| | | (Principal Financial Officer) |

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Exhibit Index

| Exhibit Number | Description |
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* Filed herewith.

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;">Balance, September 30, 2018
$
—

$
12.1

$
—

$
—

$
—

$
12.1

The changes in AOCI by component, net of tax, for the nine month period ended September 30, 2018 were as follows (in millions):

| | Post-retirement benefit plans | Currency translation adjustment | Unrealized holding gains on securities | Derivatives | Deferred Tax Asset Valuation Allowance | Total |
|---|---|---|---|---|---|---|
| Attributable to ATI: | | | | | | |
| Balance, December 31, 2017 | $ (954.5) | $ (53.5) | $ — | $ 9.0 | $ (28.8) | $ (1,027.8) |
| OCI before reclassifications | — | (11.2) | — | 1.9 | — | (9.3) |
| Amounts reclassified from AOCI | (a) 42.3 | (b) — | (b) — | (c) (7.8) | (d) 11.3 | 45.8 |
| Net current-period OCI | 42.3 | (11.2) | — | (5.9) | 11.3 | 36.5 |
| Balance, September 30, 2018 | $ (912.2) | $ (64.7) | $ — | $ 3.1 | $ (17.5) | $ (991.3) |
| Attributable to noncontrolling interests: | | | | | | |
| Balance, December 31, 2017 | $ — | $ 17.3 | $ — | $ — | $ — | $ 17.3 |
| OCI before reclassifications | — | (5.2) | — | — | — | (5.2) |
| Amounts reclassified from AOCI | — | (b) — | — | — | — | — |
| Net current-period OCI | — | (5.2) | — | — | — | (5.2) |
| Balance, September 30, 2018 | $ — | $ 12.1 | $ — | $ — | $ — | $ 12.1 |

(a) Amounts were included in net periodic benefit cost for pension and other postretirement benefit plans (see Note 9).
(b) No amounts were reclassified to earnings.
(c) Amounts related to derivatives are included in cost of goods sold or interest expense in the period or periods the hedged item affects earnings (see Note 7).

(d) Represents the net change in deferred tax asset valuation allowances on changes in AOCI balances between the balance sheet dates.

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The changes in AOCI by component, net of tax, for the three month period ended September 30, 2017 were as follows (in millions):

| | Post-retirement benefit plans | Currency translation adjustment | Unrealized holding gains on securities | Derivatives | Deferred Tax Asset Valuation Allowance | Total |
|---|---|---|---|---|---|---|
| Attributable to ATI: | | | | | | |
| Balance, June 30, 2017 | $ (943.5) | $ (72.4) | $ — | $ (5.7) | $ (45.6) | $ (1,067.2) |
| OCI before reclassifications | — | 19.2 | — | 5.7 | — | 24.9 |
| Amounts reclassified from AOCI | (a) 10.5 | (b) — | (b) — | (c) (0.8) | 16.3 | 26.0 |
| Net current-period OCI | 10.5 | 19.2 | — | 4.9 | 16.3 | 50.9 |
| Balance, September 30, 2017 | $ (933.0) | $ (53.2) | $ — | $ (0.8) | $ (29.3) | $ (1,016.3) |
| Attributable to noncontrolling interests: | | | | | | |
| Balance, June 30, 2017 | $ — | $ 11.9 | $ — | $ — | $ — | $ 11.9 |
| OCI before reclassifications | — | 5.0 | — | — | — | 5.0 |
| Amounts reclassified from AOCI | — | (b) — | — | — | — | — |
| Net current-period OCI | — | 5.0 | — | — | — | $ 5.0 |
| Balance, September 30, 2017 | $ — | $ 16.9 | $ — | $ — | $ — | $ 16.9 |

The changes in AOCI by component, net of tax, for the nine month period ended September 30, 2017 were as follows (in millions):

| | Post-retirement benefit plans | Currency translation adjustment | Unrealized holding gains on securities | Derivatives | Deferred Tax Asset Valuation Allowance | Total |
|---|---|---|---|---|---|---|
| Attributable to ATI: | | | | | | |
| Balance, December 31, 2016 | $ (965.5) | $ (85.0) | $ — | $ 2.4 | $ (45.6) | $ (1,093.7) |
| OCI before reclassifications | — | 31.8 | — | (1.0) | — | 30.8 |
| Amounts reclassified from AOCI | (a) 32.5 | (b) — | (b) — | (c) (2.2) | 16.3 | 46.6 |
| Net current-period OCI | 32.5 | 31.8 | — | (3.2) | 16.3 | 77.4 |
| Balance, September 30, 2017 | $ (933.0) | $ (53.2) | $ — | $ (0.8) | $ (29.3) | $ (1,016.3) |
| Attributable to noncontrolling interests: | | | | | | |
| Balance, December 31, 2016 | $ — | $ 9.7 | $ — | $ — | $ — | $ 9.7 |
| OCI before reclassifications | — | 7.2 | — | — | — | 7.2 |
| Amounts reclassified from AOCI | — | (b) — | — | — | — | — |
| Net current-period OCI | — | 7.2 | — | — | — | $ 7.2 |
| Balance, September 30, 2017 | $ — | $ 16.9 | $ — | $ — | $ — | $ 16.9 |

(a) Amounts were included in net periodic benefit cost for pension and other postretirement benefit plans (see Note 9).
(b) No amounts were reclassified to earnings.
(c) Amounts related to the effective portion of the derivatives are included in cost of goods sold in the period or periods the hedged item affects earnings (see Note 7).

Other comprehensive income (loss) amounts (OCI) reported above by category are net of applicable income tax expense (benefit) for each year presented. Income tax expense (benefit) on OCI items is recorded as a change in a deferred tax asset or liability. Amounts recognized in OCI include the impact of any deferred tax asset valuation allowances, when applicable, resulting from the Company’s three year cumulative loss position. Foreign currency translation adjustments, including those pertaining to noncontrolling interests, are generally not adjusted for income taxes as they relate to indefinite investments in non-U.S. subsidiaries.

Reclassifications out of AOCI for the three and nine month periods ended September 30, 2018 and 2017 were as follows:

| Details about AOCI Components (In millions) | Amount reclassified from AOCI Three months ended September 30, 2018 | Three months ended September 30, 2017 | Nine months ended September 30, 2018 | Nine months ended September 30, 2017 | | Affected line item in the statements of operations |
|---|---|---|---|---|---|---|
| Postretirement benefit plans | | | | | | |
| Prior service credit | $0.7 | $ 0.4 | $ 1.9 | $ 1.2 | (a) | |
| Actuarial losses | (19.2) | (17.8) | (57.5) | (53.6) | (a) | |
| | (18.5) | (17.4) | (55.6) | (52.4) | (c) | Total before tax |
| | (4.5) | (6.9) | (13.3) | (19.9) | | Tax provision (benefit) (d) |
| | $(14.0) | $ (10.5) | $ (42.3) | $ (32.5) | | Net of tax |
| Derivatives | | | | | | |
| Nickel and other raw material contracts | $2.2 | $ (1.5) | $ 10.4 | $ (4.0) | (b) | |
| Natural gas contracts | — | (1.1) | (0.5) | (4.5) | (b) | |
| Foreign exchange contracts | 0.5 | 3.8 | 0.5 | 12.0 | (b) | |
| Interest rate swap | (0.1) | — | (0.1) | — | (b) | |
| | 2.6 | 1.2 | 10.3 | 3.5 | (c) | Total before tax |
| | 0.6 | 0.4 | 2.5 | 1.3 | | Tax provision (benefit) (d) |
| | $2.0 | $ 0.8 | $ 7.8 | $ 2.2 | | Net of tax |

(a) Amounts are reported in nonoperating retirement benefit expense (see Note 9).

(b) Amounts related to derivatives, with the exception of the interest rate swap are included in cost of goods sold in the period or periods the hedged item affects earnings. Amounts related to the interest rate swap are included in interest expense in the same period as the interest expense on the Term Loan is recognized in earnings (see Note 7).

(c) For pretax items, positive amounts are income and negative amounts are expense in terms of the impact to net income. Tax effects are presented in conformity with ATI’s presentation in the consolidated statements of operations.

(d) These amounts exclude the impact of any deferred tax asset valuation allowance, when applicable.

Note 15. Commitments and Contingencies

The Company is subject to various domestic and international environmental laws and regulations that govern the discharge of pollutants and disposal of wastes, and which may require that it investigate and remediate the effects of the release or disposal of materials at sites associated with past and present operations. The Company could incur substantial cleanup costs, fines, and civil or criminal sanctions, third party property damage or personal injury claims as a result of violations or liabilities under these laws or noncompliance with environmental permits required at its facilities. The Company is currently involved in the investigation and remediation of a number of its current and former sites, as well as third party sites.

Environmental liabilities are recorded when the Company’s liability is probable and the costs are reasonably estimable. In many cases, however, the Company is not able to determine whether it is liable or, if liability is probable, to reasonably estimate the loss or range of loss. Estimates of the Company’s liability remain subject to additional uncertainties, including the nature and extent of site contamination, available remediation alternatives, the extent of corrective actions that may be required, and the number, participation, and financial condition of other potentially responsible parties (PRPs). The Company adjusts its accruals to reflect new information as appropriate. Future

adjustments could have a material adverse effect on the Company's consolidated results of operations in a given period, but the Company cannot reliably predict the amounts of such future adjustments.
At September 30, 2018, the Company's reserves for environmental remediation obligations totaled approximately $15 million, of which $9 million was included in other current liabilities. The reserve includes estimated probable future costs of $3 million for federal Superfund and comparable state-managed sites; $11 million for formerly owned or operated sites for which the Company has remediation or indemnification obligations; and $1 million for owned or controlled sites at which Company operations have been discontinued. The timing of expenditures depends on a number of factors that vary by site. The Company expects that it will expend present accruals over many years and that remediation of all sites with which it has been

identified will be completed within thirty years. The Company continues to evaluate whether it may be able to recover a portion of past and future costs for environmental liabilities from third parties and to pursue such recoveries where appropriate.

Based on currently available information, it is reasonably possible that costs for recorded matters may exceed the Company’s recorded reserves by as much as $16 million. Future investigation or remediation activities may result in the discovery of additional hazardous materials, potentially higher levels of contamination than discovered during prior investigation, and may impact costs of the success or lack thereof in remedial solutions. Therefore, future developments, administrative actions or liabilities relating to environmental matters could have a material adverse effect on the Company’s consolidated financial condition or results of operations.

See Note 20. Commitments and Contingencies to the Company’s consolidated financial statements in the Company’s Annual Report on Form 10-K for its fiscal year ended December 31, 2017 for a discussion of legal proceedings affecting the Company.

A number of other lawsuits, claims and proceedings have been or may be asserted against the Company relating to the conduct of its currently and formerly owned businesses, including those pertaining to product liability, environmental, health and safety matters and occupational disease (including as each relates to alleged asbestos exposure), as well as patent infringement, commercial, government contracting, construction, employment, employee and retiree benefits, taxes, environmental, and stockholder and corporate governance matters. While the outcome of litigation cannot be predicted with certainty, and some of these lawsuits, claims or proceedings may be determined adversely to the Company, management does not believe that the disposition of any such pending matters is likely to have a material adverse effect on the Company’s financial condition or liquidity, although the resolution in any reporting period of one or more of these matters could have a material adverse effect on the Company’s consolidated results of operations for that period.

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

### Overview

ATI is a global manufacturer of technically advanced specialty materials and complex components. Our largest markets are aerospace & defense, which together represent approximately 50% of total sales, led by products for jet engines. Additionally, we have a strong presence in the oil & gas, electrical energy, medical, and automotive markets. In aggregate, these key markets represent about 80% of our revenue. ATI is a market leader in manufacturing differentiated products that require our unique manufacturing and precision machining capabilities as well as our innovative new product development competence. Our capabilities range from alloy development to final production of highly engineered finished components. We are a leader in producing powders for use in next-generation jet engine forgings and 3D-printed aerospace products.

ATI reported third quarter 2018 sales of $1.02 billion and income before tax of $62.5 million, compared to sales of $869.1 million and a loss before tax of $121.3 million for the third quarter 2017. Our gross profit was $160.4 million, or 15.7% of sales, a $55.1 million improvement compared to the third quarter 2017, reflecting the benefits of our growing position on next-generation commercial aerospace programs. Results for the third quarter 2017 include a pre-tax non-cash goodwill impairment charge of $114.4 million ($113.6 million after-tax, or $1.05 per share) for ATI Cast Products, our titanium investment casting business in the High Performance Materials & Components (HPMC) segment. Gross profit and operating profit now reflect required accounting changes to classify the non-service cost components of retirement benefit expense as nonoperating expenses. Prior period results were restated for this required reporting change, which did not affect pre-tax or net-of-tax results, or how ATI calculates business segment operating profit. Net income attributable to ATI was $50.5 million, or $0.37 per share, in the third quarter 2018 compared to a net loss attributable to ATI of $121.2 million, or $(1.12) per share, for the third quarter 2017. Results in both 2018 and 2017 include impacts from income taxes that differ from applicable standard tax rates, primarily related to the income tax valuation allowance.

We operate in two business segments, HPMC and Flat Rolled Products (FRP). Compared to the third quarter 2017, sales increased 14% in the HPMC segment and 22% in the FRP segment. Sales to the commercial aerospace market, which represented 65% of third quarter 2018 HPMC sales, were 18% higher than the third quarter 2017, including a 21% increase in commercial airframe product sales and a 16% increase in sales to the commercial jet engine market.

In addition, HPMC third quarter sales included higher demand in the construction and mining and medical markets, which improved 36% and 6%, respectively, versus the prior year period. The increase in sales in the FRP segment was due to 26% higher sales of high-value products, primarily nickel-based and specialty alloys, and 13% higher sales of standard products.

Results for the first nine months of 2018 included sales of $3.01 billion and income before tax of $208.5 million, compared to sales of $2.62 billion and a loss before tax of $86.9 million for the first nine months of 2017. Our gross profit for the first nine months of 2018 was $482.7 million, or 16.0% of sales, a $128.3 million improvement compared to the first nine months of

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2017. Results for 2018 include a $15.9 million pre-tax gain on the sale of a 50% noncontrolling interest and subsequent deconsolidation of the Allegheny & Tsingshan Stainless (A&T Stainless) joint venture in March 2018. ATI's 2017 results include the third quarter's $114.4 million pre-tax goodwill impairment charge. Net income attributable to ATI was $181.3 million, or $1.31 per share, in the first nine months of 2018, compared to a net loss attributable to ATI of $93.6 million, or $(0.87) per share, for the first nine months of 2017.

Compared to the first nine months of 2017, sales for the first nine months of 2018 increased 12% in the HPMC business segment and 19% in the FRP business segment. HPMC sales reflect stronger demand for forged components and nickel-based and specialty alloys mill products. FRP's sales compared to the prior year period include stronger shipments of high-value products, primarily for nickel-based and specialty alloys.

ATI's sales to the aerospace & defense markets increased 17%, to $499.2 million in the third quarter 2018, compared to the third quarter 2017. HPMC sales of next-generation jet engine products, which represented 48% of total third quarter 2018 HPMC jet engine product sales, increased 42% compared to the third quarter 2017. The HPMC segment typically experiences modest seasonal weakness in the third quarter of each fiscal year due to many European customers, particularly in the aerospace supply chain, taking plant outages during this summer period. ATI also typically performs corresponding annual preventative maintenance outages at several facilities during this same period.

Demand from the global aerospace & defense, oil & gas, electrical energy, automotive and medical markets represented 81% of our sales for the three months ended September 30, 2018 and 78% for the three months ended September 30, 2017. Comparative information for our overall revenues (in millions) by market and their respective percentages of total revenues for the three and nine month periods ended September 30, 2018 and 2017 were as follows:

| Markets | Three months ended September 30, 2018 | | | Three months ended September 30, 2017 | | |
|---|---|---|---|---|---|---|
| Aerospace & Defense | $499.2 | 49 | % | $427.7 | 49 | % |
| Oil & Gas | 128.2 | 13 | % | 98.4 | 11 | % |
| Automotive | 85.0 | 8 | % | 61.7 | 7 | % |
| Electrical Energy | 59.9 | 6 | % | 48.5 | 6 | % |
| Medical | 47.9 | 5 | % | 44.5 | 5 | % |
| Subtotal - Key Markets | 820.2 | 81 | % | 680.8 | 78 | % |
| Food Equipment & Appliances | 58.8 | 6 | % | 54.5 | 6 | % |
| Construction/Mining | 58.4 | 6 | % | 48.3 | 6 | % |
| Electronics/Computers/Communication | 41.3 | 3 | % | 42.3 | 5 | % |
| Other | 41.5 | 4 | % | 43.2 | 5 | % |
| Total | $1,020.2 | 100 | % | $869.1 | 100 | % |

| Markets | Nine months ended September 30, 2018 | | | Nine months ended September 30, 2017 | | |
|---|---|---|---|---|---|---|
| Aerospace & Defense | $1,443.6 | 48 | % | $1,280.5 | 49 | % |
| Oil & Gas | 413.5 | 14 | % | 289.7 | 11 | % |
| Automotive | 244.5 | 8 | % | 206.4 | 8 | % |
| Electrical Energy | 180.3 | 6 | % | 144.2 | 6 | % |
| Medical | 142.8 | 5 | % | 142.7 | 5 | % |
| Subtotal - Key Markets | 2,424.7 | 81 | % | 2,063.5 | 79 | % |
| Food Equipment & Appliances | 181.3 | 6 | % | 168.9 | 6 | % |
| Construction/Mining | 169.9 | 6 | % | 144.6 | 6 | % |
| Electronics/Computers/Communication | 109.7 | 3 | % | 108.2 | 4 | % |

| | | | | |
|---|---|---|---|---|
| Other | 123.1 | 4 % | 130.0 | 5 % |
| Total | $3,008.7 | 100% | $2,615.2 | 100% |

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For the third quarter 2018, international sales increased 14% to $413 million and represented 40% of total sales, compared to $363 million, or 42% of total sales, for the third quarter 2017. For the first nine months of 2018, international sales increased 20% to $1.27 billion and represented 42% of total sales, compared to $1.06 billion, or 41% of total sales, for the first nine months of 2017. ATI's international sales are mostly to the aerospace, oil & gas, electrical energy, automotive and medical markets.

Sales of our high-value products represented 84% of total sales, the majority of which were consumed by our aerospace & defense customers, for the three and nine months ended September 30, 2018. Comparative information for our major high-value and standard products based on their percentages of our total sales is as follows:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| High-Value Products | | | | |
| Nickel-based alloys and specialty alloys | 30 % | 28 % | 30 % | 27 % |
| Precision forgings, castings and components | 18 % | 19 % | 20 % | 19 % |
| Titanium and titanium-based alloys | 16 % | 17 % | 15 % | 17 % |
| Precision and engineered strip | 14 % | 14 % | 14 % | 14 % |
| Zirconium and related alloys | 6 % | 6 % | 5 % | 6 % |
| Total High-Value Products | 84 % | 84 % | 84 % | 83 % |
| Standard Products | | | | |
| Stainless steel sheet | 9 % | 9 % | 9 % | 9 % |
| Specialty stainless sheet | 4 % | 4 % | 4 % | 4 % |
| Stainless steel plate and other | 3 % | 3 % | 3 % | 4 % |
| Total Standard Products | 16 % | 16 % | 16 % | 17 % |
| Grand Total | 100% | 100% | 100% | 100% |

Segment operating profit for the third quarter 2018 was $105.5 million, or 10.3% of sales, compared to the third quarter 2017 segment operating profit of $54.4 million, or 6.3% of sales. For the first nine months of 2018, segment operating profit was $325.9 million, or 10.8% of sales, compared to segment operating profit of $195.2 million, or 7.5% of sales, for the first nine months of 2017. Segment operating profit as a percentage of sales by business segment for the three and nine month periods ended September 30, 2018 and 2017 was:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| High Performance Materials & Components | 13.0% | 12.0 % | 14.9% | 11.7% |
| Flat Rolled Products | 6.8 % | (2.0 )% | 5.2 % | 1.4 % |

On March 1, 2018, we announced the formation of the A&T Stainless joint venture with an affiliate company of Tsingshan Group (Tsingshan) to produce 60-inch wide stainless sheet products for sale in North America. The A&T Stainless operations include ATI's previously-idled direct roll and pickle (DRAP) facility in Midland, PA. ATI provides hot-rolling conversion services to A&T Stainless using the FRP segment's Hot-Rolling and Processing Facility (HRPF). Tsingshan purchased its 50% joint venture interest for $17.5 million, of which $12.0 million was received in the first nine months of 2018. As a result of this sale of a 50% non-controlling interest and the subsequent deconsolidation of the A&T Stainless entity, we recognized a $15.9 million pre-tax gain in the first quarter of 2018, which is reported in other income, net, on the consolidated statement of operations for the nine months ended September 30, 2018 and excluded from FRP segment results.

In the HPMC segment, we expect continued year-over-year revenue and operating profit growth in the fourth quarter 2018 resulting from ongoing aerospace market demand growth and improved asset utilization. We reiterate our guidance for a full year 2018 segment operating profit margin improvement of approximately 300 basis points compared to 2017. We remain confident in our customers' elevated order patterns due to increasing jet engine build rates over the next several years. Our focus is on strong operational execution and on meeting our aerospace customer's production requirements regardless of aircraft build rate.

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In the FRP segment, significant price declines in several key raw materials are expected to result in weaker fourth quarter 2018 results due to the short-term mismatch between input costs and the surcharge index pricing mechanism. We anticipate our U.S. Operations to remain profitable in the fourth quarter despite these higher input costs. Even with these short-term headwinds, we continue to expect a 2018 year-over-year operating margin improvement of 150 to 300 basis points driven by continued strong end-market demand, ongoing growth of our differentiated product sales, and the benefits from improved HRPF utilization.

Year-over-year cost inflation in many raw materials used to manufacture our products is likely to represent a moderate LIFO expense headwind in the fourth quarter of 2018 which would be greater than, and not fully offset by, our remaining net realizable value (NRV) inventory reserves.

Cash generation from operations remains a key focus, and we intend to carefully balance our working capital and other cash needs with the pace of our capital expenditures. We expect strong fourth quarter 2018 cash generation, and expect to end 2018 with zero borrowings under our ABL revolving credit facility.

Business Segment Results

High Performance Materials & Components Segment

Third quarter 2018 sales increased 14.2% to $585.5 million compared to the third quarter 2017, primarily due to stronger demand for nickel-based and specialty alloy products, forgings and components. Demand in the aerospace & defense markets continues to drive HPMC results as sales to these markets represented 76% of third quarter segment sales: 46% commercial jet engine, 19% commercial airframe, and 11% government aero/defense. Sales to the commercial aerospace market, which represented 65% of third quarter 2018 sales, were 18% higher than the prior year, including a 21% increase in commercial airframe product sales and a 16% increase in sales to the commercial jet engine market. Next-generation jet engine products, which represent 48% of HPMC jet engine product sales, increased 42% compared to the prior year. Construction and mining market sales were 36% higher, and medical market sales were 6% higher from prior year.

Comparative information for our HPMC segment revenues (in millions) by market and their respective percentages of the segment's overall revenues for the three month periods ended September 30, 2018 and 2017 is as follows:

| Markets | Three months ended September 30, 2018 | | Three months ended September 30, 2017 | |
|---|---|---|---|---|
| Aerospace & Defense: | | | | |
| Commercial Jet Engines | $270.1 | 46 % | $232.4 | 45 % |
| Commercial Airframes | 112.1 | 19 % | 93.0 | 18 % |
| Government Aerospace & Defense | 64.3 | 11 % | 64.1 | 13 % |
| Total Aerospace & Defense | 446.5 | 76 % | 389.5 | 76 % |
| Medical | 44.3 | 8 % | 41.8 | 8 % |
| Electrical Energy | 30.9 | 5 % | 30.4 | 6 % |
| Construction/Mining | 18.5 | 3 % | 13.5 | 3 % |
| Oil & Gas | 17.9 | 3 % | 14.3 | 3 % |
| Other | 27.4 | 5 % | 23.4 | 4 % |
| Total | $585.5 | 100 % | $512.9 | 100 % |

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International sales represented 46% of total segment sales for the third quarter 2018. Third quarter 2018 reflects higher sales of specialty alloy products and components. Comparative information for the HPMC segment's major product categories, based on their percentages of sales for the three months ended September 30, 2018 and 2017, is as follows:

| | Three months ended September 30, 2018 | 2017 |
|---|---|---|
| High-Value Products | | |
| Precision forgings, castings and components | 33 % | 33 % |
| Nickel-based alloys and specialty alloys | 32 % | 30 % |
| Titanium and titanium-based alloys | 25 % | 26 % |
| Zirconium and related alloys | 10 % | 11 % |
| Total High-Value Products | 100% | 100% |

Segment operating profit in the third quarter 2018 increased to $76.0 million, or 13.0% of total sales, compared to $61.7 million, or 12.0% of total sales, for the third quarter 2017. This operating profit improvement reflects higher productivity from increasing aerospace and defense sales, and an improved product mix of next-generation nickel alloys and forgings for the aero engine market. Prior year results included $2 million of start-up costs for our nickel-based powder alloys facility in North Carolina.

For the nine months ended September 30, 2018, segment sales increased 12.2% to $1.74 billion, compared to the first nine months of 2017, primarily due to 22% higher sales of forged and cast components and 15% higher sales of nickel-based and specialty alloy products. Demand in the aerospace & defense markets continues to drive HPMC results as sales to the commercial aerospace market were 15% higher than the first nine months of 2017. Construction and mining market sales were 46% higher, and electrical energy market sales were 21% higher both from a low prior-year base, while sales to the medical market were 2% lower primarily due to increased competition in MRI end uses.

Comparative information for our HPMC segment revenues (in millions) by market and their respective percentages of the segment's overall revenues for the nine month periods ended September 30, 2018 and 2017 is as follows:

| Markets | Nine months ended September 30, 2018 | | Nine months ended September 30, 2017 | |
|---|---|---|---|---|
| Aerospace & Defense: | | | | |
| Commercial Jet Engines | $813.0 | 47 % | $686.1 | 44 % |
| Commercial Airframes | 307.4 | 17 % | 290.4 | 19 % |
| Government Aerospace & Defense | 191.3 | 11 % | 193.2 | 13 % |
| Total Aerospace & Defense | 1,311.7 | 75 % | 1,169.7 | 76 % |
| Medical | 131.5 | 8 % | 134.2 | 9 % |
| Electrical Energy | 101.9 | 6 % | 84.1 | 5 % |
| Construction/Mining | 55.1 | 3 % | 37.6 | 2 % |
| Oil & Gas | 51.4 | 3 % | 49.7 | 3 % |
| Other | 86.5 | 5 % | 74.4 | 5 % |
| Total | $1,738.1 | 100% | $1,549.7 | 100% |

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International sales represented 48% of total segment sales for the first nine months of 2018. Comparative information for the HPMC segment's major product categories, based on their percentages of sales for the nine months ended September 30, 2018 and 2017, is as follows:

| | Nine months ended September 30, 2018 | 2017 |
|---|---|---|
| High-Value Products | | |
| Precision forgings, castings and components | 35 % | 32 % |
| Nickel-based alloys and specialty alloys | 31 % | 30 % |
| Titanium and titanium-based alloys | 24 % | 27 % |
| Zirconium and related alloys | 10 % | 11 % |
| Total High-Value Products | 100% | 100% |

Segment operating profit in the first nine months of 2018 increased to $259.4 million, or 14.9% of total sales, compared to $180.6 million, or 11.7% of total sales, for the first nine months of 2017. This operating profit improvement reflects higher productivity from increasing aerospace and defense sales, and an improved product mix of next-generation nickel alloys and forgings for the aero engine market. Prior year results included $6 million of start-up costs for our nickel-based powder alloys facility in North Carolina.

Flat Rolled Products Segment

Third quarter 2018 sales increased 22% compared to the third quarter 2017, to $434.7 million, due to 26% higher sales of high-value products, primarily nickel-based and specialty alloys and Precision Rolled strip products. Sales of standard products were 13% higher, compared to the third quarter 2017. Sales to the oil & gas and automotive markets increased 31% and 40%, respectively, versus the prior year period. Third quarter 2018 FRP segment titanium shipments, including Uniti joint venture conversion, were 1.6 million pounds, a 43% increase compared to the third quarter 2017, reflecting stronger project-based demand from industrial titanium markets.

Comparative information for our FRP segment revenues (in millions) by market and their respective percentages of the segment's overall revenues for the three month periods ended September 30, 2018 and 2017 is as follows:

| Markets | Three months ended September 30, 2018 | | Three months ended September 30, 2017 | |
|---|---|---|---|---|
| Oil & Gas | $110.3 | 25 % | $84.1 | 23 % |
| Automotive | 83.0 | 19 % | 59.3 | 17 % |
| Food Equipment & Appliances | 58.6 | 14 % | 54.3 | 15 % |
| Aerospace & Defense | 52.7 | 12 % | 38.2 | 11 % |
| Electronics/Computers/Communication | 40.3 | 9 % | 41.2 | 12 % |
| Construction/Mining | 39.9 | 9 % | 34.8 | 10 % |
| Electrical Energy | 29.0 | 7 % | 18.1 | 5 % |
| Other | 20.9 | 5 % | 26.2 | 7 % |
| Total | $434.7 | 100% | $356.2 | 100% |

International sales represented 33% of total segment sales for the third quarter 2018. Third quarter 2018 reflects higher sales of high-value products largely due to demand for nickel-based and specialty alloys for large oil & gas projects, as well as higher selling prices including both raw material surcharges and improved base pricing.

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Comparative information for the FRP products segment's major product categories, based on their percentages of sales for the three months ended September 30, 2018 and 2017, is as follows:

| | Three months ended September 30, 2018 | 2017 |
|---|---|---|
| High-Value Products | | |
| Precision and engineered strip | 34 % | 34 % |
| Nickel-based alloys and specialty alloys | 29 % | 27 % |
| Titanium and titanium-based alloys | 3 % | 3 % |
| Total High-Value Products | 66 % | 64 % |
| Standard Products | | |
| Stainless steel sheet | 20 % | 20 % |
| Specialty stainless sheet | 9 % | 11 % |
| Stainless steel plate | 5 % | 5 % |
| Total Standard Products | 34 % | 36 % |
| Grand Total | 100% | 100% |

Segment operating profit was $29.5 million, or 6.8% of sales, for the third quarter 2018, compared to a segment operating loss of $7.3 million, or (2.0)% of sales, for the third quarter 2017. Compared to 2017, results in 2018 included a better matching of raw material surcharges with changes in prices for nickel, ferrochrome and other metallics, and improved cost absorption through higher operating rates. Results also benefited from continued strong market demand and ongoing improvements in asset utilization.

We continue to make progress toward our FRP segment goal of capital efficient asset utilization improvements as evidenced by our recently announced agreement to provide carbon steel hot-rolling conversion services for NLMK USA at our world-class HRPF. Slab shipments to ATI will begin in October 2018 and increase to anticipated levels in first quarter 2019.

In late March 2018, ATI filed for an exclusion from the recently enacted Section 232 tariffs on behalf of the A&T Stainless JV, which imports semi-finished stainless slab products from Indonesia. In the absence of an exclusion, these slabs will be subject to the 25% tariff recently levied on all stainless steel products imported into the United States. We continue to work within the U.S. Commerce Department's Section 232 tariff exclusion request process to secure an exclusion on behalf of the A&T Stainless joint venture. Third quarter 2018 results of A&T Stainless were negatively impacted by these tariffs.

Comparative shipment volume and average selling price information of the segment's products for the three months ended September 30, 2018 and 2017 is provided in the following table:

| | Three months ended September 30, 2018 | 2017 | % Change |
|---|---|---|---|
| Volume (000's pounds): | | | |
| High-Value | 87,994 | 83,637 | 5 % |
| Standard | 96,211 | 115,907 | (17 )% |
| Total | 184,205 | 199,544 | (8 )% |
| Average prices (per lb.): | | | |
| High-Value | $3.22 | $ 2.69 | 20 % |
| Standard | $1.53 | $ 1.13 | 35 % |
| Combined Average | $2.34 | $ 1.78 | 31 % |

For the first nine months of 2018, sales increased 19.2% compared to the first nine months of 2017, to $1.27 billion, due to higher sales of high-value products, primarily nickel-based and specialty alloys and Precision Rolled strip products. Sales to the oil & gas market increased 51% versus the prior year period, which was primarily due to large international pipeline projects. The first nine months of 2018 FRP segment titanium shipments, including Uniti joint venture conversion, were 5.0 million pounds, a 24% increase compared to the first nine months of 2017, reflecting stronger project-based demand from industrial titanium markets.

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Comparative information for our FRP segment revenues (in millions) by market and their respective percentages of the segment's overall revenues for the nine month periods ended September 30, 2018 and 2017 is as follows:

| Markets | Nine months ended September 30, 2018 | | Nine months ended September 30, 2017 | |
|---|---|---|---|---|
| Oil & Gas | $362.1 | 29 % | $240.0 | 22 % |
| Automotive | 237.1 | 19 % | 200.0 | 19 % |
| Food Equipment & Appliances | 181.0 | 14 % | 167.9 | 16 % |
| Aerospace & Defense | 131.9 | 10 % | 110.8 | 10 % |
| Construction/Mining | 114.8 | 9 % | 107.0 | 10 % |
| Electronics/Computers/Communication | 105.0 | 8 % | 104.7 | 10 % |
| Electrical Energy | 78.4 | 6 % | 60.1 | 6 % |
| Other | 60.3 | 5 % | 75.0 | 7 % |
| Total | $1,270.6 | 100% | $1,065.5 | 100% |

International sales represented 34% of total segment sales for the first nine months of 2018. Comparative information for the FRP products segment's major product categories, based on their percentages of sales for the nine months ended September 30, 2018 and 2017, is as follows:

| | Nine months ended September 30, 2018 | 2017 |
|---|---|---|
| High-Value Products | | |
| Precision and engineered strip | 32 % | 34 % |
| Nickel-based alloys and specialty alloys | 29 % | 23 % |
| Titanium and titanium-based alloys | 5 % | 4 % |
| Total High-Value Products | 66 % | 61 % |
| Standard Products | | |
| Stainless steel sheet | 20 % | 22 % |
| Specialty stainless sheet | 10 % | 12 % |
| Stainless steel plate | 4 % | 5 % |
| Total Standard Products | 34 % | 39 % |
| Grand Total | 100% | 100% |

Segment operating profit was $66.5 million, or 5.2% of sales, for the first nine months of 2018, compared to a segment operating profit of $14.6 million, or 1.4% of sales, for the first nine months of 2017. Compared to 2017, results in 2018 included a better matching of raw material surcharges with changes in prices for nickel, ferrochrome and other metallics and improved cost absorption through higher operating rates. Results also benefited from continued strong market demand and ongoing improvements in asset utilization. FRP results for 2018 included approximately $8 million of negative impacts from required accounting changes on retirement benefit cost capitalization in inventory, as well as reduced benefits of foreign currency hedges. Prior year results also reflect $6 million of higher raw material surcharge benefits related primarily to a change in the ferrochrome surcharge calculation.

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Comparative shipment volume and average selling price information of the segment's products for the nine months ended September 30, 2018 and 2017 is provided in the following table:

| | Nine months ended September 30, 2018 | 2017 | % Change |
|---|---|---|---|
| Volume (000's pounds): | | | |
| High-Value | 256,601 | 233,059 | 10 % |
| Standard | 310,466 | 345,569 | (10 )% |
| Total | 567,067 | 578,628 | (2 )% |
| Average prices (per lb.): | | | |
| High-Value | $3.22 | $ 2.76 | 17 % |
| Standard | $1.40 | $ 1.20 | 17 % |
| Combined Average | $2.22 | $ 1.83 | 21 % |

Corporate Items

There was no net effect of changes in last-in, first-out (LIFO) and net realizable value (NRV) inventory reserves for the third quarter and nine months ended September 30, 2018. For the third quarter and first nine months of 2018, LIFO inventory valuation reserve charges of $2.0 million and $29.5 million, respectively, were offset by reductions of the same magnitude in NRV inventory reserves, which are required to offset the Company's aggregate net debit LIFO inventory balance that exceeds current inventory replacement cost. For the third quarter and first nine months of 2017, LIFO inventory valuation reserve charges of $33.3 million and $51.5 million, respectively, were offset by $33.2 million and $51.3 million, respectively in reductions in NRV inventory reserves.

Corporate expenses for the third quarters of both 2018 and 2017 were $14.8 million. For the nine months ended September 30, 2018, corporate expenses were $40.9 million, increasing from $36.9 million for the nine months ended September 30, 2017. This increase was primarily due to higher incentive compensation expense based on estimates of attaining performance measures. In addition, higher start-up research and development costs of our meltless titanium alloy powder joint venture with GE Aviation in 2018 were partially offset by higher benefits in 2018 related to company-owned life insurance policies.

Closed operations and other expenses for the third quarter 2018 decreased to $3.4 million, compared to $12.2 million for the third quarter 2017, primarily due to lower carrying costs for closed facilities, mainly related to property taxes and insurance expense for Rowley, UT and Midland, PA locations. For the nine months ended September 30, 2018, closed company and other expenses decreased to $16.6 million, compared to $28.4 million for the comparable period, largely due to foreign currency remeasurement gains in 2018 compared to remeasurement losses in 2017 from the Company's European Treasury Center operation, partially offset by higher environmental expenses at closed and formerly-owned operations. The year-to-date 2018 period also benefited from lower carrying costs from closed facilities.

On March 1, 2018, we announced the formation of A&T Stainless, in which ATI has a 50% ownership interest. Our joint venture partner purchased its 50% joint venture interest during the first quarter of 2018, and as a result of this sale and the subsequent deconsolidation of the A&T Stainless entity, we recognized a $15.9 million gain in the first quarter of 2018. This gain is reported in other income, net, on the consolidated statement of operations for the nine months ended September 30, 2018 and excluded from FRP segment results.

During the third quarter of 2017, we recorded a $114.4 million goodwill impairment charge to write-off all the goodwill
assigned to ATI Cast Products, our titanium investment casting business in the HPMC segment. This goodwill impairment charge was excluded from 2017 HPMC business segment results.

Interest expense, net of interest income, in the third quarter 2018 was $24.8 million, compared to net interest expense of $34.2 million in the third quarter 2017. On a year-to-date basis, net interest expense was $75.8 million for the first nine months of 2018 compared to $102.2 million for the first nine months of 2017. These decreases are primarily due to the redemption of our 9.375% Senior Notes due 2019 in the fourth quarter of 2017. Capitalized interest reduced interest expense by $1.4 million in the third quarter 2018 and $0.4 million in the third quarter 2017. For the nine months ended September 30, 2018 and 2017, capitalized interest was $3.5 million and $1.9 million, respectively.

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Income Taxes

ATI maintains income tax valuation allowances on its U.S. Federal and state deferred tax assets due to a three year cumulative loss condition, which limits the ability to consider other positive subjective evidence, such as projections of future results, to assess the realizability of deferred tax assets. Results in both 2018 and 2017 include impacts from income taxes that differ from applicable standard tax rates, primarily related to income tax valuation allowances.

Third quarter 2018 results included a provision for income taxes of $6.9 million, or 11.0% of income before income taxes, primarily related to income taxes on non-U.S. operations. The overall income tax provision for the third quarter 2018 includes discrete adjustments of $0.9 million of tax expense resulting from tax expense related to uncertain tax positions, impact of change in tax rates and tax calculations for entities excluded from the annual effective tax rate.

The third quarter 2017 benefit for income taxes was $1.9 million, which included $0.3 million of discrete tax benefits.

We continue to account for impacts of the Tax Cuts and Jobs Act (Tax Act) as estimated amounts, pending further information and analysis, which includes final tax return filings, analysis of foreign earnings and profits, and interpretive Internal Revenue Service (IRS) guidance. We estimated the impact of the Tax Act as part of the 2017 year-end financial statements. Additional IRS guidance and Internal Revenue Code (IRC) elections have been published, which have aided in refining the initial estimate related to the tax on the mandatory repatriation of foreign earnings, otherwise known as the "transition tax". As of December 31, 2017, our initial estimate was approximately $100 million of federal taxable income on the mandatory repatriation of foreign earnings (foreign earnings inclusion), for which we planned to utilize a portion of our federal net operating loss (NOL) deferred tax asset to fully offset the estimated transition tax liability of $35 million. As of September 30, 2018, our updated foreign earnings inclusion estimate is $97.5 million, resulting in a transition tax liability of $34.1 million. We currently expect to opt out of utilizing NOLs to offset the transition tax liability, and instead utilize available tax credits of $28.2 million. The remaining transition tax liability of $5.9 million was recognized as a discrete charge in the income tax provision in the second quarter of 2018 based on updated IRS guidance, our evaluation of various tax assets, and the expected IRC election to utilize tax credits to meet a portion of the transition tax. The transition tax liability is payable over eight years under the IRC, and the first installment payment of $0.5 million was paid in April 2018.

The adoption of this strategy would preserve $97.5 million federal NOL tax attributes that we expect to be able to utilize to offset future taxable income, while using tax credits that would potentially expire due to utilization limitations. The overall impact on our deferred tax assets as of December 31, 2017 is zero due to the net valuation allowance position. Due to final regulations not being issued, the accounting for this item is not yet complete. We expect to complete the accounting within the prescribed one-year measurement period from the Tax Act enactment date.

Discrete tax benefits of $5.8 million were recognized in the first nine months of 2018 relating to valuation allowance releases resulting from the acceptance of net operating loss carryback claims and amendments of historical tax returns due to changes in estimated tax credit utilization resulting from recently-issued IRS guidance.

For the nine months of 2018, the provision for income taxes was $16.8 million, or 8.1%, compared to a benefit for income taxes of $2.0 million, for the comparable 2017 period. The first nine months of 2018 included discrete tax expense of $0.9 million, while the comparable 2017 period included discrete tax benefits of $7.0 million, largely for the effects of amending tax returns for prior periods in certain domestic jurisdictions.

Financial Condition and Liquidity

We have a $500 million Asset Based Lending (ABL) Credit Facility, which is collateralized by the accounts receivable and inventory of our domestic operations. The ABL facility, which matures in February 2022, includes a $400 million revolving credit facility, a letter of credit sub-facility of up to $200 million, and a $100 million term loan (Term Loan). The Term Loan has an interest rate of 3.0% plus a LIBOR spread and can be prepaid in increments of $50 million if certain minimum liquidity conditions are satisfied. In July 2018, the ABL facility was amended to reduce the Term Loan base interest rate to 2.5% plus a LIBOR spread. In conjunction with this amendment, we entered into a $50 million floating-for-fixed interest rate swap which converts half of the Term Loan to a 5.44% fixed interest rate. The swap matures in January 2021.

The applicable interest rate for revolving credit borrowings under the ABL facility includes interest rate spreads based on available borrowing capacity that range between 1.75% and 2.25% for LIBOR-based borrowings and between

1.0% and 1.5% for base rate borrowings. The ABL facility contains a financial covenant whereby we must maintain a fixed charge coverage ratio of not less than 1.00:1.00 after an event of default has occurred and is continuing or if the undrawn availability under the ABL revolving credit portion of the facility is less than the greater of (i) 10% of the then applicable maximum borrowing amount under the revolving credit portion of the ABL and any outstanding Term Loan balance, or (ii) $40.0 million. We were in compliance with the fixed charge coverage ratio covenant at September 30, 2018. Additionally, we must demonstrate liquidity, as calculated in accordance with the terms of the ABL facility, of at least $700 million on the date that is 91 days prior to January 15, 2021, the maturity date of the 5.95% Senior Notes due 2021, and that such liquidity is available at all times thereafter until the 5.95% Senior Notes due 2021 are paid in full or refinanced. As of September 30, 2018, there were no of outstanding borrowings under the revolving portion of the ABL facility, and $35.1 million was utilized to support the issuance of letters of credit. Average revolving credit borrowings under the ABL facility for the first nine months of 2018 and 2017 were $56 million and $46 million, respectively, bearing an average annual interest rate of 3.65% and 3.276%, respectively.

At September 30, 2018, we had $154 million of cash and cash equivalents, and available additional liquidity under the ABL facility of approximately $360 million. We do not expect to pay any significant U.S. federal or state income taxes in the next few years due to net operating loss carryforwards.

Our fiscal year 2018 funding requirements to the ATI Pension Plan, our U.S. qualified defined benefit pension plan, are approximately $40 million, of which $15 million was contributed through September 30, 2018, and we currently expect to have average annual funding requirements of approximately $100 million to the ATI Pension Plan for the next few fiscal years thereafter. However, these funding estimates are subject to significant uncertainty including the actual pension trust assets' fair value, and the discount rates used to measure pension liabilities.

We believe that internally generated funds, current cash on hand and available borrowings under the ABL facility will be adequate to meet our liquidity needs, including currently projected required contributions to the ATI Pension Plan. If we needed to obtain additional financing using the credit markets, the cost and the terms and conditions of such borrowings may be influenced by our credit rating. In addition, we regularly review our capital structure, various financing alternatives and conditions in the debt and equity markets in order to opportunistically enhance our capital structure. In connection therewith, we may seek to refinance or retire existing indebtedness, incur new or additional indebtedness or issue equity or equity-linked securities, in each case, depending on market and other conditions.

We have no off-balance sheet arrangements as defined in Item 303(a)(4) of SEC Regulation S-K.

Cash Flow and Working Capital

For the nine months ended September 30, 2018, cash provided by operations was $116.6 million, despite a $99.4 million use from higher managed working capital balances to support higher demand. In addition, cash used in operations in the first nine months of 2018 includes $22.1 million in short-term advances for our funding of the A&T Stainless joint venture during its production ramp-up and a $15.3 million cash contribution to the ATI Pension Plan made in July 2018. The cash used in operations of $53.8 million for the nine months ended September 30, 2017 included a $135.0 million contribution to the ATI Pension Plan in March 2017.

As part of managing the liquidity of our business, we focus on controlling managed working capital, which is defined as gross accounts receivable, short-term contract assets and gross inventories, less accounts payable and short-term contract liabilities. With the adoption of the new revenue recognition accounting standard in 2018, we now include short-term contract assets and liabilities in the calculation of managed working capital. In 2017 and prior periods, portions of contract assets and liabilities were included in managed working capital. Prior managed working capital calculations were not revised for this accounting change. In measuring performance in controlling managed working capital, we exclude the effects of LIFO and other inventory valuation reserves, and reserves for uncollectible accounts receivable which, due to their nature, are managed separately. We measure managed working capital as a percentage of the prior three months annualized sales to evaluate our performance based on recent levels of business volume. At September 30, 2018, managed working capital decreased to 36.4% of annualized total ATI sales compared to 38.1% of annualized sales at December 31, 2017, as revenue growth continued. The $99.4 million increase in managed working capital at September 30, 2018 from December 31, 2017 resulted from a $43.3 million increase in accounts receivable, $51.6 million in short-term contract assets, a $69.7 million increase in inventory, and a $4.0 million decrease in accounts payable, partially offset by $69.2 million in short-term contract liabilities. Days sales outstanding, which measures actual collection timing for accounts receivable, improved by 11% as of September 30, 2018 compared to year end 2017. Gross inventory turns, which exclude the effect of LIFO and any applicable offsetting NRV inventory valuation reserves, remained fairly consistent at September 30, 2018 compared to year end 2017.

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The components of managed working capital at September 30, 2018 and December 31, 2017 were as follows:

| (In millions) | September 30, 2018 | December 31, 2017 |
|---|---|---|
| Accounts receivable | $588.3 | $ 545.3 |
| Short-term contract assets | 51.6 | — |
| Inventory | 1,239.8 | 1,176.1 |
| Accounts payable | (416.1 ) | (420.1 ) |
| Short-term contract liabilities | (69.2 ) | — |
| Subtotal | 1,394.4 | 1,301.3 |
| Allowance for doubtful accounts | 6.2 | 5.9 |
| Adjustment from current cost to LIFO cost basis | (1.7 ) | (43.1 ) |
| Inventory valuation reserves | 86.1 | 121.5 |
| Managed working capital | $1,485.0 | $ 1,385.6 |
| Annualized prior 3 months sales | $4,080.8 | $ 3,639.5 |
| Managed working capital as a % of annualized sales | 36.4 % | 38.1 % |
| Change in managed working capital from December 31, 2017 | $99.4 | |

Cash used in investing activities was $109.1 million in the first nine months of 2017, with $101.3 million for capital expenditures and $10.0 million for the Addaero acquisition. The 2018 capital expenditures include initial down payments for the previously announced HPMC iso-thermal press and heat-treating expansions, as well as significant expenditures on our STAL joint venture's expansion in China, which was placed in service in the third quarter 2018. The STAL joint venture expansion has been funded entirely through joint venture cash and operations. We expect to fund our capital expenditures with cash on hand and cash flow generated from our operations and, if needed, by using a portion of the ABL facility.

Cash provided by financing activities was $4.4 million and consisted primarily of $2.7 million for the sale of noncontrolling interest related to Next Gen Alloys, and $12.0 million for the first two installments from our joint venture partner of the $17.5 million purchase price for its 50% joint venture interest in A&T Stainless. These were partially offset by $10.0 million in dividend payments to the 40% noncontrolling interest in our STAL joint venture.

At September 30, 2018, cash and cash equivalents on hand totaled $153.5 million, an increase of $11.9 million from year end 2017. Cash and cash equivalents held by our foreign subsidiaries was $61.0 million at September 30, 2018, of which $30.0 million was held by STAL.

Debt

Total debt outstanding increased $9.2 million to $1,563.0 million at September 30, 2018 compared to December 31, 2017.

In managing our overall capital structure, some of the measures on which we focus are net debt to total capitalization, which is the percentage of our debt, net of cash that may be available to reduce borrowings, to our total invested and borrowed capital, and total debt to total capitalization, which excludes cash balances. Net debt as a percentage of total capitalization was 41.6% at September 30, 2018, compared to 44.8% at December 31, 2017. The net debt to total capitalization was determined as follows:

| (In millions) | September 30, 2018 | December 31, 2017 |
|---|---|---|
| Total debt (a) | $1,563.0 | $1,553.8 |
| Less: Cash | (153.5 ) | (141.6 ) |
| Net debt | $1,409.5 | $1,412.2 |
| Total ATI stockholders' equity | 1,980.2 | 1,739.4 |
| Net ATI total capital | $3,389.7 | $3,151.6 |
| Net debt to ATI total capital | 41.6 % | 44.8 % |

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Total debt to total capitalization of 44.1% at September 30, 2018 decreased from 47.2% at December 31, 2017. Total debt to total capitalization was determined as follows:

| (In millions) | September 30, 2018 | December 31, 2017 |
|---|---|---|
| Total debt (a) | $1,563.0 | $1,553.8 |
| Total ATI stockholders' equity | 1,980.2 | 1,739.4 |
| Total ATI capital | $3,543.2 | $3,293.2 |
| Total debt to total ATI capital | 44.1 % | 47.2 % |

(a) Excludes debt issuance costs.

Dividends

Effective with the fourth quarter of 2016, our Board of Directors decided to suspend the quarterly dividend. The payment of dividends and the amount of such dividends depends upon matters deemed relevant by our Board of Directors on a quarterly basis, such as our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by law, credit agreements or senior securities, and other factors deemed relevant and appropriate. Under the ABL facility, there is no limit on dividend declarations or payments provided that the undrawn availability, after giving effect to a particular dividend payment, is at least the greater of $100 million and 25% of the maximum revolving credit availability, and no event of default under the ABL facility has occurred and is continuing or would result from paying the dividend. In addition, there is no limit on dividend declarations or payments if the undrawn availability is less than the greater of $100 million and 25% of the maximum revolving credit advance amount but more than the greater of $60 million and 15% of the maximum revolving credit advance amount, if (i) no event of default has occurred and is continuing or would result from paying the dividend, (ii) we demonstrate to the administrative agent that, prior to and after giving effect to the payment of the dividend (A) the undrawn availability, as measured both at the time of the dividend payment and as an average for the 60 consecutive day period immediately preceding the dividend payment, is at least the greater of $60 million and 15% of the maximum revolving credit availability, and (B) we maintain a fixed charge coverage ratio of at least 1.00:1.00, as calculated in accordance with the terms of the ABL facility.

Critical Accounting Policies

Inventory

At September 30, 2018, we had net inventory of $1,239.8 million. Inventories are stated at the lower of cost (LIFO, first-in, first-out (FIFO) and average cost methods) or market. Costs include direct material, direct labor and applicable manufacturing and engineering overhead, and other direct costs. Most of our inventory is valued utilizing the LIFO costing methodology. Inventory of our non-U.S. operations is valued using average cost or FIFO methods. Under the LIFO inventory valuation method, changes in the cost of raw materials and production activities are recognized in cost of sales in the current period even though these material and other costs may have been incurred at significantly different values due to the length of time of our production cycle. In a period of rising prices, cost of sales expense recognized under LIFO is generally higher than the cash costs incurred to acquire the inventory sold. Conversely, in a period of declining raw material prices, cost of sales recognized under LIFO is generally lower than cash costs incurred to acquire the inventory sold. Generally, over time based on overall inflationary trends in raw materials, labor and overhead costs, the use of the LIFO inventory valuation method will result in a LIFO inventory valuation reserve, as the higher current period costs are included in cost of sales and the balance sheet carrying value of inventory is reduced.

Since the LIFO inventory valuation methodology is designed for annual determination, interim estimates of the annual LIFO valuation are required. We recognize the effects of the LIFO inventory valuation method on an interim basis by projecting the expected annual LIFO cost and allocating that projection to the interim quarters equally. These projections of annual LIFO inventory valuation reserve changes are updated quarterly and are evaluated based upon material, labor and overhead costs and projections for such costs at the end of the year plus projections regarding year end inventory levels.

The prices for many of the raw materials we use have been extremely volatile during the past several years, while labor and overhead costs have been generally stable, with a modest inflationary trend. Raw material cost changes typically have the largest impact on the LIFO inventory costing methodology based on the overall proportion of raw material costs to other inventoriable costs. Since we value most of our inventory utilizing the LIFO inventory costing methodology, a fall in material costs generally results in a benefit to operating results by reducing cost of sales and increasing the inventory carrying value, while conversely, a rise in raw material costs generally has a negative effect on our operating results by increasing cost of sales while lowering the carrying value of inventory. For example, for the nine months ended September 30, 2018 and 2017, the LIFO inventory valuation method resulted in cost of sales that were $29.5 million and $51.5 million higher, respectively, than would have been recognized under the FIFO methodology to value our inventory.

Due primarily to persistent raw material deflation in prior years, we are in the unusual situation of having a LIFO inventory balance that exceeds replacement cost. In cases where inventory at FIFO cost is lower than the LIFO carrying value, a write-down of the inventory to market may be required, subject to a lower of cost or market evaluation. In applying the lower of cost or market principle, market means current replacement cost, subject to a ceiling (market value shall not exceed net realizable value) and a floor (market shall not be less than net realizable value reduced by an allowance for a normal profit margin). We evaluate product lines on a quarterly basis to identify inventory values that exceed estimated net realizable value. The calculation of a resulting NRV inventory reserve, if any, is recognized in the period that the need for the reserve is identified. Our NRV reserves were $47.5 million at December 31, 2017 and $6.2 million at September 30, 2018. If our third quarter 2018 projection of the annual LIFO inventory valuation remains unchanged, we would recognize another $9.8 million of LIFO expense in the fourth quarter of 2018, which would be partially offset by the reversal of the remaining $6.2 million of NRV reserves.
The impact to our cost of sales for changes in the LIFO costing methodology and associated NRV inventory reserves were as follows (in millions):

| | Nine months ended September 30, | |
|---|---|---|
| | 2018 | 2017 |
| LIFO benefit (charge) | $(29.5) | $(51.5) |
| NRV benefit (charge) | 29.5 | 51.3 |
| Net cost of sales impact | $— | $(0.2) |

It is our general policy to write-down to scrap value any inventory that is identified as obsolete and any inventory that has aged or has not moved in more than twelve months. In some instances this criterion is up to twenty-four months due to the longer manufacturing and distribution process for such products.
The LIFO inventory valuation methodology is not utilized by many of the companies with which we compete, including foreign competitors. As such, our results of operations may not be comparable to those of our competitors during periods of volatile material costs due, in part, to the differences between the LIFO inventory valuation method and other acceptable inventory valuation methods.
Asset Impairment
We monitor the recoverability of the carrying value of our long-lived assets. An impairment charge is recognized when the expected net undiscounted future cash flows from an asset's use (including any proceeds from disposition) are less than the asset's carrying value, and the asset's carrying value exceeds its fair value. Changes in the expected use of a long-lived asset group, and the financial performance of the long-lived asset group and its operating segment, are evaluated as indicators of possible impairment. Future cash flow value may include appraisals for property, plant and equipment, land and improvements, future cash flow estimates from operating the long-lived assets, and other operating considerations. In the fourth quarter of each year in conjunction with the annual business planning cycle, or more frequently if new material information is available, we evaluate the recoverability of idled facilities.

Goodwill is reviewed annually in the fourth quarter of each year for impairment or more frequently if impairment indicators arise. Other events and changes in circumstances may also require goodwill to be tested for impairment between annual measurement dates. At September 30, 2018, we had $536.4 million of goodwill on our consolidated balance sheet, an increase of $5.0 million from December 31, 2017 due to $6.0 from the Addaero acquisition partially offset by foreign currency translation on goodwill denominated in functional currencies other than the U.S. dollar. All goodwill relates to reporting units in the HPMC segment.
Management concluded that none of ATI's reporting units or long-lived assets experienced any triggering event that would have required an interim impairment analysis at September 30, 2018.

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Income Taxes

The provision for, or benefit from, income taxes includes deferred taxes resulting from temporary differences in income for financial and tax purposes using the liability method. Such temporary differences result primarily from differences in the carrying value of assets and liabilities. Future realization of deferred income tax assets requires sufficient taxable income within the carryback and/or carryforward period available under tax law. On a quarterly basis, we evaluate the realizability of our deferred tax assets.

The evaluation includes the consideration of all available evidence, both positive and negative, regarding historical operating results including recent years with reported losses, the estimated timing of future reversals of existing taxable temporary differences, estimated future taxable income exclusive of reversing temporary differences and carryforwards, and potential tax planning strategies which may be employed to prevent an operating loss or tax credit carryforward from expiring unused. In situations where a three year cumulative loss condition exists, accounting standards limit the ability to consider projections of future results as positive evidence to assess the realizability of deferred tax assets. Valuation allowances are established when it is estimated that it is more likely than not that the tax benefit of the deferred tax asset will not be realized.

Since 2015, our results reflected a three year cumulative loss from U.S. operations. As a result, we established deferred tax asset valuation allowances in 2015 and 2016 for certain U.S. Federal and state deferred tax assets. In 2017 and 2018, ATI continued to maintain income tax valuation allowances on its U.S. Federal and state deferred tax assets. In addition, we have $17.5 million of valuation allowances on amounts recorded in other comprehensive income as of September 30, 2018.

While we remain in a cumulative loss condition, our ability to evaluate the realizability of deferred tax assets is generally limited to the ability to offset timing differences on taxable income associated with deferred tax liabilities. Therefore, a change in estimate of deferred tax asset valuation allowances for federal, state, or foreign jurisdictions during this cumulative loss condition period will primarily be affected by changes in estimates of the time periods that deferred tax assets and liabilities will be realized, or on a limited basis to tax planning strategies that may result in a change in the amount of taxable income realized.

On December 22, 2017, the U.S. government enacted the Tax Act. We estimated the impact of the Tax Act as part of the 2017 year-end financial statements. We continue to account for impacts of Tax Act as estimated amounts, pending further information and analysis, which includes final tax return filings, analysis of foreign earnings and profits, and interpretive IRS guidance. Additional IRS guidance and IRC elections have been published, which have aided in refining the initial estimate related to the tax on the mandatory repatriation of foreign earnings, otherwise known as the “transition tax”. As of December 31, 2017, our initial estimate was approximately $100 million of federal taxable income on the mandatory repatriation of foreign earnings (foreign earnings inclusion), for which we planned to utilize a portion of our federal net operating loss (NOL) deferred tax asset to fully offset the estimated transition tax liability of $35 million. As of September 30, 2018, our updated foreign earnings inclusion estimate is $97.5 million, resulting in a transition tax liability of $34.1 million. We currently expect to opt out of utilizing NOLs to offset the transition tax liability, and instead utilize available tax credits of $28.2 million. The remaining transition tax liability of $5.9 million was recognized as a discrete charge in the income tax provision for the second quarter of 2018 based on updated IRS guidance, our evaluation of various tax assets, and the expected IRC election to utilize tax credits to meet a portion of the transition tax. The transition tax liability is payable over eight years under the IRC, and the first installment payment of $0.5 million was paid in April 2018. The overall impact on our deferred tax assets as of December 31, 2017 is zero due to the net valuation allowance position. Due to final regulations not being issued, the accounting for this item is not yet complete. We expect to complete the accounting within the prescribed one-year measurement period from the Tax Act enactment date.

Retirement Benefits

In accordance with accounting standards, we determine the discount rate used to value pension plan liabilities as of the last day
of each year. The discount rate reflects the current rate at which the pension liabilities could be effectively settled. In

estimating this rate, we receive input from our actuaries regarding the rate of return on high quality, fixed income investments
with maturities matched to the expected future retirement benefit payments. Based on current market conditions, discount rates
are above the rates in effect at the year-end 2017 remeasurement date, when a 3.85% discount rate was used for valuing
pension liabilities. The estimated effect at the year-end 2017 valuation date of an increase in the discount rate by 0.50% would
decrease pension liabilities by approximately $150 million. The effect on pension liabilities for changes to the discount rate, the difference between expected and actual plan asset returns, and the net effect of other changes in actuarial assumptions and
experience are deferred and amortized over future periods in accordance with accounting standards.

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For ERISA (Employee Retirement Income Security Act of 1974, as amended) funding purposes, discount rates used to measure pension liabilities for U.S. qualified defined benefit plans are calculated on a different basis using an IRS-determined segmented yield curve, which currently results in a higher discount rate than the discount rate methodology required by accounting standards. Funding requirements are also affected by IRS-determined mortality assumptions, which may differ from those used under accounting standards. Our fiscal year 2018 funding requirements to the ATI Pension are approximately $40 million, of which $15 million was contributed through September 30, 2018, and we currently expect have annual average funding requirements of approximately $100 million to the ATI Pension Plan for the next few fiscal years thereafter. However, these funding estimates are subject to significant uncertainty including the actual pension trust assets' fair value, and the discount rates used to measure pension liabilities.

We currently use a long-term expected rate of return on plan assets of 7.75%. The effect of increasing or lowering the expected
return on pension plan investments by 0.25% would result in additional pre-tax income or expense, respectively, of approximately $5 million annually, as a component of net periodic pension cost in the period subsequent to the change in
estimate.

Other Critical Accounting Policies

A summary of other significant accounting policies is discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 1 to the consolidated financial statements contained in our Annual Report on Form 10-K for the year ended December 31, 2017.

The preparation of the financial statements in accordance with U.S. generally accepted accounting principles requires us to make judgments, estimates and assumptions regarding uncertainties that affect the reported amounts of assets and liabilities. Significant areas of uncertainty that require judgments, estimates and assumptions include the accounting for derivatives, retirement plans, income taxes, environmental and other contingencies as well as asset impairment, inventory valuation and collectability of accounts receivable. We use historical and other information that we consider to be relevant to make these judgments and estimates. However, actual results may differ from those estimates and assumptions that are used to prepare our financial statements.

Pending Accounting Pronouncements

See Note 1 of the Notes to Consolidated Financial Statements for information on pending accounting pronouncements.

Forward-Looking and Other Statements

From time to time, we have made and may continue to make "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Certain statements in this report relate to future events and expectations and, as such, constitute forward-looking statements. Forward-looking statements include those containing such words as "anticipates," "believes," "estimates," "expects," "would," "should," "will," "will likely result," "fore
"outlook," "projects," and similar expressions. Forward-looking statements are based on management's current expectations and include known and unknown risks, uncertainties and other factors, many of which we are unable to predict or control, that may cause our actual results, performance or achievements to differ materially from those expressed or implied in the forward-looking statements. Important factors that could cause actual results to differ materially from those in the forward-looking statements include: (a) material adverse changes in economic or industry conditions generally, including global supply and demand conditions and prices for our specialty metals and changes in international trade duties and other aspects of international trade policy; (b) material adverse changes in the markets we serve; (c) our inability to achieve the level of cost savings, productivity improvements, synergies, growth or other benefits anticipated by management, from strategic investments and the integration of acquired businesses;
(d) volatility in the price and availability of the raw materials that are critical to the manufacture of our products;
(e) declines in the value of our defined benefit pension plan assets or unfavorable changes in laws or regulations that govern pension plan funding; (f) labor disputes or work stoppages; (g) equipment outages; and (h) other risk factors

summarized in our Annual Report on Form 10-K for the year ended December 31, 2017, and in other reports filed with the Securities and Exchange Commission. We assume no duty to update our forward-looking statements.

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## Item 3. Quantitative and Qualitative Disclosures About Market Risk

As part of our risk management strategy, we utilize derivative financial instruments, from time to time, to hedge our exposure to changes in energy and raw material prices, foreign currencies, and interest rates. We monitor the third-party financial institutions which are our counterparties to these financial instruments on a daily basis and diversify our transactions among counterparties to minimize exposure to any one of these entities. Fair values for derivatives were measured using exchange-traded prices for the hedged items including consideration of counterparty risk and the Company's credit risk. Our exposure to volatility in interest rates is presently not material, as nearly all of our debt is at fixed interest rates.

Volatility of Interest Rates. We may enter into derivative interest rate contracts to maintain a reasonable balance between fixed- and floating-rate debt. In July 2018, we entered into a $50 million floating-for-fixed interest rate swap which converts half of the Term Loan to a 5.44% fixed interest rate. The Company designated the interest rate swap as a cash flow hedge of the Company's exposure to the variability of the payment of interest on a portion of its Term Loan borrowings. The swap matures in January 2021. Any gain or loss associated with this hedging arrangement is included in interest expense. At September 30, 2018, the net mark-to-market valuation of the outstanding interest rate swap was an unrealized pre-tax loss of $0.1 million, comprised of $0.1 million in other long-term assets and $0.2 million in accrued liabilities.

Volatility of Energy Prices. Energy resources markets are subject to conditions that create uncertainty in the prices and availability of energy resources. The prices for and availability of electricity, natural gas, oil and other energy resources are subject to volatile market conditions. These market conditions often are affected by political and economic factors beyond our control. Increases in energy costs, or changes in costs relative to energy costs paid by competitors, have and may continue to adversely affect our profitability. To the extent that these uncertainties cause suppliers and customers to be more cost sensitive, increased energy prices may have an adverse effect on our results of operations and financial condition. We use approximately 8 to 10 million MMBtu's of natural gas annually, depending upon business conditions, in the manufacture of our products. These purchases of natural gas expose us to risk of higher gas prices. For example, a hypothetical $1.00 per MMBtu increase in the price of natural gas would result in increased annual energy costs of approximately $8 to $10 million. We use several approaches to minimize any material adverse effect on our results of operations or financial condition from volatile energy prices. These approaches include incorporating an energy surcharge on many of our products and using financial derivatives to reduce exposure to energy price volatility.

At September 30, 2018, the outstanding financial derivatives used to hedge our exposure to energy cost volatility included natural gas hedges. Approximately 35% of our forecasted domestic requirements for natural gas for the remainder of 2018, approximately 35% for 2019 and approximately 30% for 2020 are hedged. The net mark-to-market valuation of these outstanding natural gas hedges at September 30, 2018 was an unrealized pre-tax loss of $0.2 million, comprised of $0.3 million in prepaid expense and other current assets, $0.1 million in other long-term assets, $0.2 million in accrued liabilities and $0.4 million in other long-term liabilities. For the three months ended September 30, 2018, natural gas hedging activity had no impact on cost of sales.

Volatility of Raw Material Prices. We use raw materials surcharge and index mechanisms to offset the impact of increased raw material costs; however, competitive factors in the marketplace can limit our ability to institute such mechanisms, and there can be a delay between the increase in the price of raw materials and the realization of the benefit of such mechanisms. For example, in 2017, we used approximately 100 million pounds of nickel; therefore, a hypothetical change of $1.00 per pound in nickel prices would result in increased costs of approximately $100 million. In addition, in 2017, we also used approximately 400 million pounds of ferrous scrap in the production of our flat-rolled products; a hypothetical change of $0.01 per pound would result in increased costs of approximately $4 million. While we enter into raw materials futures contracts from time-to-time to hedge exposure to price fluctuations, such as for nickel, we cannot be certain that our hedge position adequately reduces exposure. We believe that we have adequate controls to monitor these contracts, but we may not be able to accurately assess exposure to price volatility in the markets for critical raw materials.

The majority of our products are sold utilizing raw material surcharges and index mechanisms. However, as of September 30, 2018, we had entered into financial hedging arrangements, primarily at the request of our customers, related to firm orders for an aggregate notional amount of approximately 12 million pounds of nickel with hedge dates through 2021. The aggregate notional amount hedged is approximately 12% of a single year's estimated nickel raw material purchase requirements. Any gain or loss associated with these hedging arrangements is included in cost of sales. At September 30, 2018, the net mark-to-market valuation of our outstanding raw material hedges was an unrealized pre-tax gain of $3.1 million, comprised of $4.3 million in prepaid expense and other current assets, $2.7 million in other long-term assets, $2.9 million in accrued liabilities and $1.0 million in other long-term liabilities on the balance sheet.

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Foreign Currency Risk. Foreign currency exchange contracts are used, from time-to-time, to limit transactional exposure to changes in currency exchange rates. We sometimes purchase foreign currency forward contracts that permit us to sell specified amounts of foreign currencies expected to be received from our export sales for pre-established U.S. dollar amounts at specified dates. The forward contracts are denominated in the same foreign currencies in which export sales are denominated. These contracts are designated as hedges of the variability in cash flows of a portion of the forecasted future export sales transactions which otherwise would expose the Company to foreign currency risk, primarily euros. At September 30, 2018, we held euro forward sales contracts designated as cash flow hedges with a notional value of approximately 16 million euros with maturity dates through May 2019. In addition, we may also designate cash balances held in foreign currencies as hedges of forecasted foreign currency transactions.

We may also enter into foreign currency forward contracts that are not designated as hedges, which are denominated in the same foreign currency in which export sales are denominated. We have 10 million euro notional value outstanding as of September 30, 2018 of foreign currency forward contracts not designated as hedges, with maturity dates into the second quarter of 2019.

At September 30, 2018, the net mark-to-market valuation of the outstanding foreign currency forward contracts was an unrealized pre-tax gain of $0.6 million, all of which was in prepaid expense and other current assets on the balance sheet.

## Item 4. Controls and Procedures

### (a) Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) or rule 15d-15(e) under the Securities Exchange Act of 1934, as amended) as of September 30, 2018, and they concluded that these disclosure controls and procedures are effective.

### (b) Changes in Internal Controls

There was no change in our internal controls over financial reporting identified in connection with the evaluation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) under the Securities Exchange Act of 1934, as amended) as of September 30, 2018 conducted by our Chief Executive Officer and Chief Financial Officer, that occurred during the quarter ended September 30, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

# PART II. OTHER INFORMATION

## Item 1. Legal Proceedings

A number of lawsuits, claims and proceedings have been or may be asserted against the Company relating to the conduct of its currently or formerly owned businesses, including those pertaining to product liability, environmental, health and safety matters and occupational disease (including as each relates to alleged asbestos exposure), as well as patent infringement, commercial, government contracting, construction, employment, employee and retiree benefits, taxes, environmental, and stockholder and corporate governance matters. Certain of such lawsuits, claims and proceedings are described in our Annual Report on Form 10-K for the year ended December 31, 2017, and addressed in Note 15 to the unaudited interim financial statements included herein. While the outcome of litigation cannot be predicted with certainty, and some of these lawsuits, claims or proceedings may be determined adversely to the Company, management does not believe that the disposition of any such pending matters is likely to have a material adverse effect on the Company’s financial condition or liquidity, although the resolution in any reporting period of one or more of these matters could have a material adverse effect on the Company’s results of operations for that period.

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Item 1A. Risk Factors

The following is an update to, and should be read in conjunction with Item 1A. Risk Factors contained in the Company's Annual Report on Form 10-K for the year ended December 31, 2017. In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Export Sales and International Trade Matters. We believe that export sales will continue to account for a significant percentage of our future revenues. We also import certain raw materials, and recently formed, together with an affiliate company of Tsingshan Group, our A&T Stainless joint venture, which will import semi-finished stainless steel slab products from Indonesia to support its U.S. production of finished 60-inch wide stainless steel sheet products for sale in North America. Risks associated with such international trade include, among others: political and economic instability, including weak conditions in the world's economies; accounts receivable collection; export controls; trade sanctions, changes in legal and regulatory requirements; policy changes affecting the markets for our products; changes in tax laws; and exchange rate fluctuations (which may affect sales to international customers and the value of profits earned on export sales when converted into dollars). Any of these factors could materially adversely affect our results for the period in which they occur.

Additionally, changes in international trade duties and other aspects of international trade policy, both in the U.S. and abroad, could materially impact our business. For example, in March 2018, the U.S. imposed an additional 25% tariff under Section 232 of the Trade Expansion Act of 1962, as amended, on steel products, including stainless steel, imported into the U.S. Currently, the semi-finished stainless steel slabs that our A&T Stainless joint venture imports from Indonesia are subject to the additional tariff. The A&T Stainless joint venture has filed for exclusions from the 232 tariff based on the nature of the imported product, its country of origin, and its lack of availability in the U.S. However, there can be no assurance that the joint venture will be successful in obtaining an exclusion for the products that it intends to import, and to the extent that no exclusion is obtained, the joint venture's operations would be impacted.

Moreover, these new tariffs, or other changes in U.S. trade policy, have resulted in, and may continue to trigger, retaliatory actions by affected countries. Certain foreign governments have instituted or are considering imposing trade sanctions on certain U.S. goods. Others are considering the imposition of sanctions that will deny U.S. companies access to critical raw materials. A "trade war" of this nature or other governmental action related to tariffs or international trade agreements or policies has the potential to adversely impact demand for our products, our costs, customers, suppliers and/or the U.S. economy or certain sectors thereof and, thus, to adversely impact our businesses.

Item 6. Exhibits

(a) Exhibits

| | |
|---|---|
| 12.1 | Computation of the Ratio of Earnings to Fixed Charges (filed herewith). |
| 31.1 | Certification of Chief Executive Officer required by Securities and Exchange Commission Rule 13a – 14(a) or 15d – 14(a) (filed herewith). |
| 31.2 | Certification of Chief Financial Officer required by Securities and Exchange Commission Rule 13a – 14(a) or 15d – 14(a) (filed herewith). |
| 32.1 | Certification pursuant to 18 U.S.C. Section 1350 (furnished herewith). |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |

| | |
|---|---|
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |

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SIGNATURES

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.

ALLEGHENY TECHNOLOGIES INCORPORATED
(Registrant)

| | | | |
|---|---|---|---|
| Date: | October 31, 2018 | By | /s/ Patrick J. DeCourcy |
| | | | Patrick J. DeCourcy |
| | | | Senior Vice President, Finance and Chief Financial Officer |
| | | | (Principal Financial Officer) |
| Date: | October 31, 2018 | By | /s/ Karl D. Schwartz |
| | | | Karl D. Schwartz |
| | | | Vice President, Controller and Chief Accounting Officer |
| | | | (Principal Accounting Officer) |