CHESAPEAKE ENERGY CORP
Form 10-Q
August 06, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Quarterly Period Ended June 30, 2014
[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to
Commission File No. 1-13726
Chesapeake Energy Corporation
(Exact name of registrant as specified in its charter)

Oklahoma	73-1395733
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6100 North Western Avenue	
Oklahoma City, Oklahoma	73118
(Address of principal executive offices)	(Zip Code)

(405) 848-8000
(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 [X] NO [ ]
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES [X] NO [ ]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer [X] Accelerated Filer [ ] Non-accelerated Filer [ ] Smaller Reporting Company [ ]
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES [ ] NO [X]
As of August 1, 2014, there were 665,775,653 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
INDEX TO FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2014

PART I. FINANCIAL INFORMATION

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$1,462	$837
Restricted cash	75	75
Accounts receivable, net	2,310	2,222
Short-term derivative assets	1	—
Deferred income tax asset	205	223
Other current assets	317	299
Total Current Assets	4,370	3,656
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Proved natural gas and oil properties ($488 and $488 attributable to our VIE)	58,914	56,157
Unproved properties	11,389	12,013
Oilfield services equipment	—	2,192
Other property and equipment	3,150	3,203
Total Property and Equipment, at Cost	73,453	73,565
Less: accumulated depreciation, depletion and amortization (($201) and ($168) attributable to our VIE)	(37,689)	(37,161)
Property and equipment held for sale, net	247	730
Total Property and Equipment, Net	36,011	37,134
LONG-TERM ASSETS:		
Investments	264	477
Long-term derivative assets	7	4
Other long-term assets	475	511
TOTAL ASSETS	$41,127	$41,782

The accompanying notes are an integral part of these condensed consolidated financial statements.
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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS – (Continued)
(Unaudited)

	June 30, 2014	December 31, 2013
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$1,930	$1,596
Short-term derivative liabilities ($9 and $5 attributable to our VIE)	417	208
Accrued interest	152	200
Other current liabilities ($20 and $22 attributable to our VIE)	3,293	3,511
Total Current Liabilities	5,792	5,515
LONG-TERM LIABILITIES:		
Long-term debt, net	11,549	12,886
Deferred income tax liabilities	3,773	3,407
Long-term derivative liabilities ($1 and $0 attributable to our VIE)	389	445
Asset retirement obligations	431	405
Other long-term liabilities	868	984
Total Long-Term Liabilities	17,010	18,127
CONTINGENCIES AND COMMITMENTS (Note 5)		
EQUITY:		
Chesapeake Stockholders’ Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,251,515 shares outstanding	3,062	3,062
Common stock, $0.01 par value, 1,000,000,000 shares authorized: 665,440,807 and 666,192,371 shares issued	7	7
Paid-in capital	12,495	12,446
Retained earnings	833	688
Accumulated other comprehensive loss	(154)	(162)
Less: treasury stock, at cost; 1,717,527 and 2,002,029 common shares	(41)	(46)
Total Chesapeake Stockholders’ Equity	16,202	15,995
Noncontrolling interests	2,123	2,145
Total Equity	18,325	18,140
TOTAL LIABILITIES AND EQUITY	$41,127	$41,782

The accompanying notes are an integral part of these condensed consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions except per share data)			
REVENUES:				
Natural gas, oil and NGL	$1,704	$2,406	$3,471	$3,858
Marketing, gathering and compression	3,167	2,057	6,182	3,838
Oilfield services	281	212	545	402
Total Revenues	5,152	4,675	10,198	8,098
OPERATING EXPENSES:				
Natural gas, oil and NGL production	282	288	570	595
Production taxes	72	59	122	112
Marketing, gathering and compression	3,166	2,028	6,147	3,772
Oilfield services	212	177	431	332
General and administrative	90	106	169	216
Restructuring and other termination costs	33	7	26	140
Natural gas, oil and NGL depreciation, depletion and amortization	661	645	1,288	1,293
Depreciation and amortization of other assets	79	76	157	154
Impairments of fixed assets and other	40	231	60	258
Net gains on sales of fixed assets	(93)	(109)	(115)	(158)
Total Operating Expenses	4,542	3,508	8,855	6,714
INCOME FROM OPERATIONS	610	1,167	1,343	1,384
OTHER INCOME (EXPENSE):				
Interest expense	(27)	(104)	(66)	(124)
Earnings (losses) on investments	(24)	23	(45)	(14)
Net gain (loss) on sales of investments	—	(10)	67	(10)
Losses on purchases of debt	(195)	(70)	(195)	(70)
Other income	7	3	13	8
Total Other Expense	(239)	(158)	(226)	(210)
INCOME BEFORE INCOME TAXES	371	1,009	1,117	1,174
INCOME TAX EXPENSE				
Current income taxes	5	2	8	3
Deferred income taxes	136	382	413	443
Total Income Tax Expense	141	384	421	446
NET INCOME	230	625	696	728
Net income attributable to noncontrolling interests	(39)	(45)	(80)	(89)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	191	580	616	639
Preferred stock dividends	(43)	(43)	(86)	(86)
Premium on purchase of preferred shares of a subsidiary	—	(69)	—	(69)
Earnings allocated to participating securities	(3)	(11)	(12)	(11)
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	$145	$457	$518	$473
EARNINGS PER COMMON SHARE:				
Basic	$0.22	$0.70	$0.79	$0.72
Diluted	$0.22	$0.66	$0.78	$0.72

CASH DIVIDEND DECLARED PER COMMON SHARE	$0.0875	$0.0875	$0.1750	$0.1750
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	659	653	658	653
Diluted	659	760	760	653

The accompanying notes are an integral part of these condensed consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
NET INCOME	$230	$625	$696	$728
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAX:				
Unrealized gain on derivative instruments, net of income tax expense of $1, $1, $3 and $0	—	1	3	—
Reclassification of (gain) loss on settled derivative instruments, net of income tax expense of $4, $0, $10 and $7	(1)	(1)	10	11
Unrealized loss on investments, net of income tax benefit of $0, $0, $0 and ($3)	—	—	—	(5)
Reclassification of (gain) loss on investment, net of income tax expense (benefit) of $0, $0, ($3) and $4	—	—	(5)	6
Other Comprehensive Income	(1)	—	8	12
COMPREHENSIVE INCOME	229	625	704	740
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(39)	(45)	(80)	(89)
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$190	$580	$624	$651

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2014	2013
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$696	$728
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,445	1,447
Deferred income tax expense	413	443
Derivative (gains) losses, net	542	(323)
Cash payments on derivative settlements, net	(323)	(49)
Stock-based compensation	40	56
Net gains on sales of fixed assets	(115)	(158)
Impairments of fixed assets and other	51	258
Losses on investments	45	7
Net (gains) losses on sales of investments	(67)	10
Restructuring and other termination costs	24	104
Losses on purchases of debt	61	17
Other	71	6
Changes in assets and liabilities	(240)	(341)
Net Cash Provided By Operating Activities	2,643	2,205
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(1,996)	(3,145)
Acquisitions of proved and unproved properties	(356)	(550)
Proceeds from divestitures of proved and unproved properties	248	1,895
Additions to other property and equipment	(620)	(506)
Proceeds from sales of other assets	713	459
Additions to investments	(5)	(4)
Proceeds from sales of investments	239	102
Decrease in restricted cash	—	170
Other	(3)	4
Net Cash Used In Investing Activities	(1,780)	(1,575)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	857	6,559
Payments on credit facilities borrowings	(1,239)	(6,578)
Proceeds from issuance of senior notes, net of discount and offering costs	2,966	2,274
Proceeds from issuance of oilfield services senior notes, net of discount and offering costs	494	—
Proceeds from issuance of oilfield services term loan, net of issuance costs	394	—
Cash paid to purchase debt	(3,362)	(1,874)
Cash paid for common stock dividends	(117)	(116)
Cash paid for preferred stock dividends	(86)	(86)
Cash paid on financing derivatives	(32)	(25)
Cash paid for prepayment of mortgage	—	(55)

Proceeds from sales of noncontrolling interests	—	5
Proceeds from other financings	—	22
Cash paid to purchase preferred shares of a subsidiary	—	(212)
Cash held and retained by SSE at spin-off	(8)	—
Distributions to noncontrolling interest owners	(105)	(111)
Other	—	(43)
Net Cash Used In Financing Activities	(238)	(240)
Net increase in cash and cash equivalents	625	390
Cash and cash equivalents, beginning of period	837	287
Cash and cash equivalents, end of period	$1,462	$677

The accompanying notes are an integral part of these condensed consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – (Continued)
(Unaudited)

Supplemental disclosures to the condensed consolidated statements of cash flows are presented below:

	Six Months Ended June 30,	
	2014	2013
	($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$88	$—
Income taxes paid, net of refunds received	$13	$13
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$(125)	$(60)
Change in accrued acquisitions of proved and unproved properties	$(60)	$54
Change in accrued additions to other property and equipment	$—	$(58)

The accompanying notes are an integral part of these condensed consolidated financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

	Six Months Ended June 30, 2014	2013
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning and end of period	$3,062	$3,062
COMMON STOCK:		
Balance, beginning and end of period	7	7
PAID-IN CAPITAL:		
Balance, beginning of period	12,446	12,293
Stock-based compensation	23	99
Tax benefit (reduction in tax benefit) from stock-based compensation	3	(12)
Exercise of stock options	23	3
Balance, end of period	12,495	12,383
RETAINED EARNINGS:		
Balance, beginning of period	688	437
Net income attributable to Chesapeake	616	639
Dividends on common stock	(117)	(116)
Dividends on preferred stock	(86)	(86)
Spin-off of oilfield services business (Note 2)	(268)	—
Premium on purchase of preferred shares of a subsidiary	—	(69)
Balance, end of period	833	805
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(162)	(182)
Hedging activity	13	11
Investment activity	(5)	1
Balance, end of period	(154)	(170)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(46)	(48)
Purchase of 10,191 and 247,183 shares for company benefit plans	—	(5)
Release of 300,034 and 106,458 shares from company benefit plans	5	1
Balance, end of period	(41)	(52)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	16,202	16,035
NONCONTROLLING INTERESTS:		
Balance, beginning of period	2,145	2,327
Sales of noncontrolling interests	—	5
Net income attributable to noncontrolling interests	80	89
Distributions to noncontrolling interest owners	(102)	(109)
Purchase of preferred shares of a subsidiary	—	(143)
Balance, end of period	2,123	2,169
TOTAL EQUITY	$18,325	$18,204

The accompanying notes are an integral part of these condensed consolidated financial statements.
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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation ("Chesapeake" or the "Company") and its subsidiaries are prepared in accordance with accounting principles generally accepted in the United States (“U.S. GAAP”) and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated. 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 U.S. GAAP.

This Form 10-Q relates to the three and six months ended June 30, 2014 (the “Current Quarter” and the “Current Period”, respectively) and the three and six months ended June 30, 2013 (the “Prior Quarter” and the “Prior Period”, respectively). Chesapeake’s annual report on Form 10-K for the year ended December 31, 2013 (“2013 Form 10-K”) includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods have been reflected. The results for the Current Quarter and the Current Period are not necessarily indicative of the results to be expected for the full year.

Risks and Uncertainties

Through our oilfield services spin-off (see Note 2), other divestitures and various other strategic transactions, we have taken steps to reduce financial leverage and complexity and further enhance our liquidity. While executing our strategic priorities, including financial discipline and profitable and efficient growth from captured resources, we have incurred certain cash outflows related to these transactions, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. As we continue to focus on our strategic priorities, certain actions that may reduce financial leverage and complexity could negatively impact our future results of operations and/or liquidity, and we may incur additional cash and noncash charges.

2. Spin-Off of Oilfield Services Business

On June 30, 2014, we completed the spin-off of our oilfield services business, which we previously conducted through our indirect, wholly owned subsidiary Chesapeake Oilfield Operating, L.L.C. (COO), into an independent, publicly traded company called Seventy Seven Energy Inc. (SSE). Following the close of business on June 30, 2014, we distributed to Chesapeake shareholders one share of SSE common stock and cash in lieu of fractional shares for every 14 shares of Chesapeake common stock held on June 19, 2014, the record date for the distribution.

Prior to the completion of the spin-off, we and COO and its affiliates engaged in the following series of transactions:

- COO and certain of its subsidiaries entered into a $275 million senior secured revolving credit facility and a $400 million secured term loan, the proceeds of which were used to repay in full and terminate COO’s existing credit facility.
- COO distributed to us its compression unit manufacturing business, its geosteering business and the proceeds from the sale of substantially all of its crude oil hauling business. See Note 13 for further discussion of the sale.
- We transferred certain of our buildings and land to a subsidiary of COO, most of which COO had been leasing from us prior to the spin-off, at carrying value.
- COO issued $500 million of 6.5% Senior Notes due 2022 in a private placement and used the net proceeds to make a cash distribution of approximately $391 million to us, to repay a portion of outstanding indebtedness under the new revolving credit facility and for general corporate purposes.
- COO converted from a limited liability company into a corporation named Seventy Seven Energy Inc.
- We distributed all of SSE’s outstanding shares to our shareholders, which resulted in SSE becoming an independent, publicly traded company.

As of June 30, 2014, following the spin-off, we have no ownership interest in SSE. Therefore, we no longer consolidate SSE’s assets and liabilities as of June 30, 2014. Because we expect to have continuing cash flows associated with SSE’s future operations through various agreements described below, our former oilfield services segment’s historical financial results for periods up to the spin-off date will continue to be included in our historical financial results as a component of continuing operations. For segment disclosures, we have labeled our oilfield services segment as “former oilfield services”. See Note 17 for additional information regarding our segments.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

In connection with the spin-off, we entered into several agreements to define the terms and conditions of the spin-off and our ongoing relationship with SSE after the spin-off, including a master separation agreement, a tax sharing agreement, an employee matters agreement, a transition services agreement, a services agreement and certain commercial agreements. These agreements, among other things, allocate responsibility for obligations arising before and after the distribution date, including obligations relating to taxes, employees, various transition services and oilfield services.

- The master separation agreement sets forth the agreements between SSE and Chesapeake regarding the principal transactions that were necessary to effect the spin-off and also sets forth other agreements that govern certain aspects of SSE's relationship with Chesapeake after the completion of the spin-off.
- The tax sharing agreement governs the respective rights, responsibilities and obligations of SSE and Chesapeake with respect to tax liabilities and benefits, tax attributes, the preparation and filing of tax returns, the control of audits and other tax proceedings, and certain other matters regarding taxes.
- The employee matters agreement addresses employee compensation and benefit plans and programs, and other related matters in connection with the spin-off, including the treatment of holders of Chesapeake common stock options, restricted stock awards, restricted stock units and performance share units, and the cooperation between SSE and Chesapeake in the sharing of employee information and maintenance of confidentiality. See Note 8 for additional information regarding the effect of the spin-off on outstanding equity compensation.
- The transition services agreement sets forth the terms on which we will provide SSE certain services. Transition services include marketing and corporate communication, human resources, information technology, security, legal, risk management, tax, environmental health and safety, maintenance, internal audit, accounting, treasury and certain other services specified in the agreement. In consideration for such services, SSE will pay Chesapeake a negotiated fee for providing those services.
- The services agreement requires us to utilize, at market-based pricing, the lesser of (i) seven, five and three pressure pumping crews in years one, two and three of the agreement, respectively, or (ii) 50% of the total number of all pressure pumping crews working for us in all of our operating regions during the respective year. We are also required to utilize SSE pressure pumping services for a minimum number of fracture stages as set forth in the agreement. We are entitled to terminate the agreement in certain situations, including if SSE fails to materially comply with the overall quality of service provided by similar service providers. As of June 30, 2014, the aggregate undiscounted minimum future payments under this agreement were approximately $283 million.
- We have also entered into drilling agreements that are rig-specific daywork drilling contracts with terms ranging from three months to three years and at market-based rates. We have the right to terminate a drilling agreement in certain circumstances. As of June 30, 2014, the aggregate undiscounted minimum future payments under these drilling agreements were approximately $393 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

Our stockholders' equity decreased by $268 million as a result of the spin-off. The following table shows the components of the decrease, which consisted of the book value of the assets and liabilities of COO as of the spin-off date of June 30, 2014. The spin-off is reflected on our condensed consolidated statement of cash flows primarily as non-cash activity.

	June 30, 2014 ($ in millions)
Assets	
Cash and cash equivalents	$8
Accounts receivable, net[(a)]	378
Other current assets	46
Total current assets	432
Oilfield services equipment	2,632
Accumulated depreciation	(900)
Investments	8
Deferred income tax asset	8
Other long-term assets	68
Total assets	$2,248
Liabilities	
Accounts payable[(a)]	$62
Accrued interest	6
Other current liabilities	180
Total current liabilities	248
Long-term debt, net	1,568
Deferred income tax liabilities	160
Asset retirement obligations	1
Other long-term liabilities	3
Total long-term liabilities	1,732
Spin-Off of Oilfield Services Business	$268

(a) Includes affiliate receivables and payables of $309 million and $8 million, respectively, that were previously eliminated in consolidation.

In the Current Quarter, we recognized $12 million of charges associated with the spin-off that are included in restructuring and other termination costs on our condensed consolidated statement of operations. See Note 15 for further details regarding these charges.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

3. Earnings Per Share

Basic earnings per share (EPS) is calculated using the weighted average number of common shares outstanding during the period and includes the effect of any participating securities as appropriate. Participating securities consist of unvested restricted stock issued to our employees and non-employee directors that provide dividend rights.

Diluted EPS is calculated assuming the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, our contingent convertible senior notes did not have a dilutive effect and therefore were excluded from the calculation of diluted EPS. See Note 4 for further discussion of our contingent convertible senior notes.

For the Current Quarter, the Current Period and the Prior Period, the following securities and associated adjustments to net income, representing dividends on such shares, were excluded from the calculation of diluted EPS as the effect was antidilutive. The impact of our stock options was immaterial in the calculation of diluted EPS for these periods.

	Net Income Adjustments ($ in millions)	Shares (in millions)
Three Months Ended June 30, 2014:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$22	59
5.75% cumulative convertible preferred stock (series A)	$16	42
5.00% cumulative convertible preferred stock (series 2005B)	$3	6
4.50% cumulative convertible preferred stock	$3	6
Unvested restricted stock	$3	3
Six Months Ended June 30, 2014:		
Common stock equivalent of our preferred stock outstanding:		
5.00% cumulative convertible preferred stock (series 2005B)	$5	6
4.50% cumulative convertible preferred stock	$6	6
Unvested restricted stock	$11	3
Six Months Ended June 30, 2013:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$43	56
5.75% cumulative convertible preferred stock (series A)	$32	39
5.00% cumulative convertible preferred stock (series 2005B)	$5	5
4.50% cumulative convertible preferred stock	$6	6
Unvested restricted stock	$11	5

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

For the Prior Quarter and the Current Period, the following securities and adjustments to net income, representing dividends on such shares, were included in the calculation of diluted EPS as the effect was dilutive. A reconciliation of basic EPS and diluted EPS for these periods is as follows:

	Net Income Available to Common Stockholders (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended June 30, 2013:			
Basic EPS	$457	653	$0.70
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	21	56	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	16	40	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	3	6	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	3	5	
Diluted EPS	$500	760	$0.66
Six Months Ended June 30, 2014:			
Basic EPS	$518	658	$0.79
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	43	59	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	32	42	
Outstanding stock options	—	1	
Diluted EPS	$593	760	$0.78

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

4. Debt

Our long-term debt consisted of the following as of June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	($ in millions)	
Term loan due 2017[(a)]	$—	$2,000
9.5% senior notes due 2015[(b)]	—	1,265
3.25% senior notes due 2016	500	500
6.25% euro-denominated senior notes due 2017[(c)]	471	473
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018[(d)]	—	97
7.25% senior notes due 2018	669	669
Floating rate senior notes due 2019	1,500	—
6.625% senior notes due 2019[(e)]	—	650
6.625% senior notes due 2020	1,300	1,300
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	1,000
5.375% senior notes due 2021	700	700
4.875% senior notes due 2022	1,500	—
5.75% senior notes due 2023	1,100	1,100
2.75% contingent convertible senior notes due 2035[(f)]	396	396
2.5% contingent convertible senior notes due 2037[(f)]	1,168	1,168
2.25% contingent convertible senior notes due 2038[(f)]	347	347
Corporate revolving bank credit facility	—	—
Oilfield services revolving bank credit facility[(g)]	—	405
Discount on senior notes and term loan[(h)]	(272)	(357)
Interest rate derivatives[(i)]	10	13
Total long-term debt, net	$11,549	$12,886

(a) In the Current Quarter, we repaid the borrowings outstanding under the term loan due 2017 with a portion of the net proceeds from our offering of $3.0 billion in aggregate principal amount of senior notes issued in the Current Quarter.

(b) In the Current Quarter, we completed a tender offer for and redemption of the 9.5% Senior Notes due 2015.

(c) The principal amount shown is based on the exchange rate of $1.3692 to €1.00 and $1.3743 to €1.00 as of June 30, 2014 and December 31, 2013, respectively. See Note 9 for information on our related foreign currency derivatives.

(d) In the Current Quarter, we redeemed all outstanding 6.875% Senior Notes due 2018.

(e) Initial issuers were COO and Chesapeake Oilfield Finance, Inc., a wholly owned subsidiary of COO. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes. In the Current Quarter, in connection with the spin-off of our oilfield services business, the obligations with respect to the COO senior notes were removed from our condensed consolidated balance sheet as of June 30, 2014. See Note 2 for further discussion of the spin-off.

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(f) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. In the second quarter of 2014, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the third quarter of 2014 under this provision. The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision in the Current Quarter or the Prior Quarter. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. Under certain conditions, we will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts (as adjusted to give effect to the dividend of SSE common stock paid in the spin-off of our oilfield services business and cash dividends on our common stock) and the ending date of the first six-month period in which contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$45.22	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$59.71	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$100.45	June 14, 2019

(g) In the Current Quarter, in connection with the spin-off of our oilfield services business, we terminated our oilfield services credit facility. See Note 2 for further discussion of the spin-off.

(h) Discount as of June 30, 2014 and December 31, 2013 included $264 million and $303 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method. Discount also included $33 million as of December 31, 2013 associated with our term loan discussed further below.

(i) See Note 9 for further discussion related to these instruments.

Term Loan

In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion. The term loan provided that it could be voluntarily repaid before November 9, 2015 at par plus a specified premium and at any time thereafter at par. The maturity date of the term loan was December 2, 2017. In the Current Quarter, the Company used a portion of the net proceeds from its offering of $3.0 billion in aggregate principal amount of senior notes to repay the borrowings under, and terminate, the term loan. We recorded a loss of $90 million, consisting of $40 million in premiums, $30 million of unamortized discount and $20 million of unamortized deferred charges, in connection with the termination.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

The Chesapeake senior notes and the contingent convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake's obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect 100% owned subsidiaries. See Note 18 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Our senior notes are governed by indentures containing covenants that may limit our ability and our subsidiaries' ability to incur certain secured indebtedness, enter into sale/leaseback transactions, and consolidate, merge or transfer assets. The indentures governing the senior notes and the contingent convertible senior notes do not have any financial or restricted payment covenants. The senior notes and contingent convertible senior notes indentures have cross default provisions that apply to other indebtedness the Company or any guarantor subsidiary may have from time to time with an outstanding principal amount of at least $50 million or $75 million, depending on the indenture.

We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance. The applicable rates for our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038 are 6.86%, 8.0% and 8.0%, respectively.

During the Current Quarter, we issued $3.0 billion in aggregate principal amount of senior notes at par. The offering included two series of notes: $1.5 billion in aggregate principal amount of Floating Rate Senior Notes due 2019 and $1.5 billion in aggregate principal amount of 4.875% Senior Notes due 2022. We used a portion of the net proceeds of $2.966 billion to repay the borrowings under, and terminate, our term loan credit facility. We used the remaining proceeds along with cash on hand to redeem the remaining $97 million principal amount of the 6.875% Senior Notes due 2018 and to purchase and redeem the remaining $1.265 billion principal amount of the 9.5% Senior Notes due 2015 for $1.454 billion. We recorded a loss of approximately $6 million associated with the redemption of the 6.875% Senior Notes due 2018, which consisted of $5 million in premiums and $1 million of unamortized deferred charges. We recorded a loss of approximately $99 million associated with the purchase and redemption of the 9.5% Senior Notes due 2015, which consisted of $87 million in premiums, $9 million of unamortized discount and $3 million of unamortized deferred charges.

During the Prior Period, we issued $2.3 billion in aggregate principal amount of senior notes at par. The offering included three series of notes: $500 million in aggregate principal amount of 3.25% Senior Notes due 2016; $700 million in aggregate principal amount of 5.375% Senior Notes due 2021; and $1.1 billion in aggregate principal amount of 5.75% Senior Notes due 2023. We used a portion of the net proceeds of $2.274 billion to repay outstanding indebtedness under our corporate revolving bank credit facility and purchase certain senior notes. We purchased $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to tender offers during the Prior Period. We recorded a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million of unamortized deferred charges. During the Prior Period, we also redeemed $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 (the "2019 Notes") at par pursuant to notice of special early redemption. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount. As described in the following paragraph, our redemption of the 2019 notes has been the subject of litigation. On July 15, 2013, we retired at maturity the remaining $247 million aggregate principal amount outstanding of our 7.625% Senior Notes due 2013.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York (the "Court") against The Bank of New York Mellon Trust Company, N.A. ("BNY Mellon"), the indenture trustee for the 2019 Notes. The Company sought a declaration that the notice it issued to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) was timely and effective pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes. BNY Mellon asserted that the notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose and because of the specific phrasing in the notice that provided it would not be effective unless the Court concluded it was timely. The Court conducted a trial on the matter and ruled in the Company's favor in May 2013. BNY Mellon filed notice of an appeal of the decision with the United States Court of Appeals for the Second Circuit and the appeal is currently pending.

No scheduled principal payments are required on our senior notes until 2016.

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Bank Credit Facilities

During the Current Period, we had the following two revolving bank credit facilities as sources of liquidity:

	Corporate Credit Facility[(a)]	Oilfield Services Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of June 30, 2014	$—	$—
Letters of credit outstanding as of June 30, 2014	$20	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower was COO. We terminated our oilfield services credit facility in the Current Quarter in connection with the spin-off of our oilfield services business. See Note 2 for further discussion of the spin-off.

Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A. or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on LIBOR, plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. Although the applicable interest rates under our corporate credit facility fluctuate based on our long-term senior unsecured credit ratings, our credit facility does not contain provisions which would trigger an acceleration of amounts due under the facility or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Our corporate credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under our corporate credit facility agreement as of June 30, 2014.

Our corporate credit facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries. If we should fail to perform our obligations under the credit facility agreement, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $50 million or more, would constitute an event of default under our senior note and contingent convertible senior note indentures, which could in turn result in the acceleration of a significant portion of such indebtedness. The credit facility agreement also has cross default provisions that apply to our secured hedging facility, equipment master lease agreements and other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million. In addition, the facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred.

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Spin-Off Debt Transactions

Prior to the spin-off of our oilfield services business, COO or its subsidiaries completed the following debt transactions:

- Entered into a five-year senior secured revolving credit facility with total commitments of $275 million and incurred approximately $3 million in financing costs related to entering into the facility.
- Entered into a $400 million seven-year secured term loan and used the net proceeds of approximately $394 million and borrowings under the new revolving credit facility to repay and terminate COO's existing credit facility.
- Issued $500 million in aggregate principal amount of 6.5% Senior Notes due 2022 in a private placement and used the net proceeds of approximately $494 million to make a cash distribution of approximately $391 million to us, to repay a portion of outstanding indebtedness under the new revolving credit facility discussed above and for general corporate purposes.

All deferred charges and debt balances related to these transactions were removed from our condensed consolidated balance sheet as of June 30, 2014. See Note 2 for further discussion of the spin-off.

Fair Value of Debt

We estimate the fair value of our exchange-traded debt using quoted market prices (Level 1). The fair value of all other debt, which consists of our credit facility and term loan, is estimated using our credit default swap rate (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	June 30, 2014		December 31, 2013	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		($ in millions)		
Long-term debt (Level 1)	$11,539	$12,802	$10,501	$11,557
Long-term debt (Level 2)	$—	$—	$2,372	$2,369

5. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.

July 2008 Common Stock Offering. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company's July 2008 common stock offering. The plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. Final judgment in favor of Chesapeake and the officer and director defendants was entered on

June 21, 2013, and the plaintiff filed a notice of appeal on July 19, 2013 in the U.S. Court of Appeals for the Tenth Circuit. The appeal has been fully briefed and oral argument was held on May 14, 2014. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

A derivative action relating to the July 2008 offering filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011 is pending. Following the denial on September 28, 2012 of its motion to dismiss and pursuant to court order, nominal defendant Chesapeake filed an answer in the case on October 12, 2012. By stipulation between the parties, the case is stayed pending resolution of the Tenth Circuit appeal of the 2009 securities class action.

2012 Securities and Shareholder Litigation. A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and its former Chief Executive Officer (CEO), Aubrey K. McClendon. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserted claims under Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company’s asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon’s personal loans and the Company’s internal controls. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. On April 10, 2013, the Court granted the motion, and on April 16, 2013, entered judgment against the plaintiff and dismissed the complaint with prejudice. The U.S. Court of Appeals for the Tenth Circuit affirmed the dismissal on July 8, 2014, and the time for further appeal has expired.

A related federal consolidated derivative action and an Oklahoma state court derivative action were stayed pursuant to the parties' stipulation pending resolution of the appeal in the 2012 federal securities class action. Following the affirmance of the dismissal of the 2012 securities class action, plaintiffs in the consolidated federal derivative action and Oklahoma state court derivative action advised the Company that they intend to proceed with their claims. The Company anticipates that plaintiffs will jointly file an amended consolidated complaint in the federal action, and that the stay of the Oklahoma state court action will remain in place.

On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company's directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company's officers and directors' use of the Company's fractionally owned corporate jets. On August 21, 2012, the District Court granted the Company's motion to dismiss for lack of derivative standing, and the plaintiff appealed the ruling on December 6, 2012. On May 16, 2014, the Court of Civil Appeals for the State of Oklahoma affirmed the dismissal. On July 7, 2014, plaintiffs filed a petition for writ of certiorari in the Oklahoma Supreme Court seeking review of the Court of Civil Appeals’ decision.

2014 Shareholder Litigation. On April 10, 2014, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against current and former directors and officers of the Company alleging, among other things, breach of fiduciary duties, waste of corporate assets, gross mismanagement and unjust enrichment related to the Company’s payment of shareholder dividends since October 2012. On July 2, 2014, the Company filed its motion to dismiss.

Regulatory Proceedings. The Company has received, from the Antitrust Division of the U.S. Department of Justice (DOJ) and certain state governmental agencies, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state laws relating to our purchase and lease of oil and gas rights in various states. Chesapeake has engaged in discussions with the DOJ and state agencies and continues to respond to such subpoenas and demands.

On March 5, 2014, the Attorney General of the State of Michigan filed a criminal complaint against Chesapeake in Michigan state court alleging misdemeanor antitrust violations and attempted antitrust violations under state law arising out of the Company’s leasing activities in Michigan during 2010. On July 9, 2014, following a preliminary hearing on the complaint, as amended, the 89th District Court for Cheboygan County, Michigan ruled that one count alleging a bid-rigging conspiracy between Chesapeake and Encana Oil & Gas USA, Inc. regarding the October 2010 state lease auction would proceed to trial and dismissed claims alleging a second antitrust violation and an attempted antitrust violation. The Michigan Attorney General filed a second criminal complaint against Chesapeake on June 5, 2014 which, as amended, alleges that Chesapeake’s conduct in canceling lease offers to Michigan landowners in 2010 violated the state’s criminal enterprises and false pretenses felony statutes. The Court has set a preliminary hearing on

this matter starting August 18, 2014.
Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims is immaterial to its consolidated financial statements.
Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. The Company has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages for royalty underpayment in various states, including cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class.
We believe losses are reasonably possible in certain of the pending royalty cases for which we have not made a loss accrual, but we are currently unable to estimate an amount or range of loss or the impact the actions could have on our future results of operations or cash flows. Plaintiffs have varying royalty provisions in their respective leases and oil and gas law varies from state to state. Royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations, an issue in a class action filed in 2010 on behalf of Oklahoma royalty owners asserting claims dating back to 2004. In July 2014, this case was remanded to the trial court for further proceedings following the reversal on appeal of certification of a statewide class. In Pennsylvania, two putative statewide class actions and one purported class arbitration were filed in 2014 on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company's divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These Pennsylvania cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act. Uncertainties in pending royalty cases generally include the complex nature of the claims and defenses, the potential size of the class in class actions, the scope and types of the properties and agreements involved, and the applicable production years.
Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.
Environmental Proceedings
The nature of the natural gas and oil business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, procedures, training and auditing to reduce and mitigate such environmental risks. Chesapeake conducts periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, Chesapeake may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.
Commitments
Compressor Leases
As of June 30, 2014, we leased 205 compressors under master lease agreements with an aggregate undiscounted future lease commitment of $33 million. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. Under the leases, we can exercise an early purchase option or we can purchase the compressors at the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew a

lease for negotiated new terms at the expiration of the lease. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. During the Current Period, we purchased 1,574 leased compressor units from various lessors for an aggregate purchase price of approximately $290 million, lowering our minimum aggregate undiscounted future compressor lease payments by approximately $202 million.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of natural gas and liquids to move certain of our production to market. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying condensed consolidated balance sheets; however, they are reflected as adjustments to natural gas, oil and NGL sales prices used in our proved reserves estimates.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners or credits for third-party volumes, are presented below.

	June 30, 2014 ($ in millions)
2014	$1,234
2015	1,883
2016	1,964
2017	1,971
2018	1,760
2019 - 2099	7,822
Total	$16,634

Drilling Contracts

We have contracts with various drilling contractors, including those entered into with SSE as discussed in Note 2, to utilize drilling services with terms ranging from three months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2014, the aggregate undiscounted minimum future payments under these drilling service commitments were approximately $501 million.

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Pressure Pumping Contracts

In April 2011, we entered into a master frac service agreement with our equity affiliate, FTS International, Inc. (FTS), which expires on December 31, 2014. Pursuant to this agreement, we are committed to enter into a predetermined number of backstop contracts, providing at least a 10% gross margin to FTS, if utilization of FTS fleets falls below a certain level. To date, we have not been required to enter into any backstop contracts. In addition, we have an agreement with a subsidiary of SSE related to pressure pumping services, which is discussed in Note 2.

Drilling Commitments

In December 2011, as part of our Utica joint venture development agreement with Total (see Note 10), we committed to spud no less than 90 cumulative Utica wells by December 31, 2012, 270 cumulative wells by December 31, 2013 and 540 cumulative wells by July 31, 2015. Through June 30, 2014, we had spud 550 cumulative Utica wells and had met our drilling commitment under the agreement.

We have also committed to drill wells in conjunction with our CHK Utica and CHK C-T financial transactions and in conjunction with the formation of the Chesapeake Granite Wash Trust. See Noncontrolling Interests in Note 7 for discussion of these transactions and commitments.

Natural Gas and Liquids Purchase Commitments

We regularly commit to purchase natural gas and liquids from other owners in the properties we operate, including owners associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices. See Note 10 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Total and Sinopec (see Note 10), we are required to extend, renew or replace expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas. To date, we have satisfied our replacement commitments under the Sinopec agreement. We have settled a dispute with Total regarding our acreage maintenance obligation as of December 31, 2012 for $50 million. The payment, which was made to Total on July 31, 2014, was based on a shortfall of approximately 20,800 net acres.

Other Commitments

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Longmont, Colorado. We also provided Sundrop with a one-time option to require us to purchase up to $25 million in additional preferred equity securities following the full payment of the initial investment, subject to the occurrence of specified milestones. As of June 30, 2014, we had funded our $155 million commitment in full and the milestones related to Sundrop's preferred equity call option had not been met. See Note 11 for further discussion of this investment.

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging, financial or performance assurances to third parties on behalf of our wholly owned guarantor subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantee our subsidiaries' future performance.

In connection with divestitures, our purchase and sale agreements generally provide indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party. These indemnifications generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or cannot be quantified at the time of the consummation of a particular transaction. In divestitures of oil and gas properties, our purchase and sale agreements may require the return of a portion of the proceeds we received as a result of uncured title defects.

Certain of our natural gas and oil properties are burdened by non-operating interests such as royalty and overriding royalty interests, including overriding royalty interests sold through our VPP transactions. As the holder of the working interest from which such interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to such interests. See Note 10 for further discussion of our VPP transactions.

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6. Other Liabilities

Other current liabilities as of June 30, 2014 and December 31, 2013 are detailed below.

	June 30, 2014	December 31, 2013
	($ in millions)	
Revenues and royalties due others	$1,426	$1,409
Accrued natural gas, oil and NGL drilling and production costs	326	457
Joint interest prepayments received	625	464
Accrued compensation and benefits	230	320
Other accrued taxes	104	161
Accrued dividends	102	101
Other	480	599
Total other current liabilities	$3,293	$3,511

Other long-term liabilities as of June 30, 2014 and December 31, 2013 are detailed below.

	June 30, 2014	December 31, 2013
	($ in millions)	
CHK Utica ORRI conveyance obligation(a)	$235	$250
CHK C-T ORRI conveyance obligation(b)	142	149
Financing obligations	30	31
Unrecognized tax benefits	201	317
Other	260	237
Total other long-term liabilities	$868	$984

(a) $16 million and $13 million of the total $251 million and $263 million obligations are recorded in other current liabilities as of June 30, 2014 and December 31, 2013, respectively. See Noncontrolling Interests in Note 7 for further discussion of the transaction.

(b) $18 million and $12 million of the total $160 million and $161 million obligations are recorded in other current liabilities as of June 30, 2014 and December 31, 2013, respectively. See Noncontrolling Interests in Note 7 for further discussion of the transaction.

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7. Equity

Common Stock

The following is a summary of the changes in our common shares issued during the Current Period and the Prior Period:

	Six Months Ended June 30,	
	2014	2013
	(in thousands)	
Shares issued as of January 1	666,192	666,468
Restricted stock issuances (net of forfeitures)[a]	(2,019)	2,138
Stock option exercises	1,268	313
Shares issued as of June 30	665,441	668,919

(a) In the second quarter of 2013, we began granting restricted stock units (RSUs) in lieu of restricted stock awards (RSAs) to non-employee directors and employees. Shares of common stock underlying RSUs are issued when the units vest, whereas restricted shares of common stock are issued on the grant date of RSAs. We refer to RSAs and RSUs collectively as restricted stock.

Preferred Stock

The following reflects the shares outstanding during the Current Period and the Prior Period, the liquidation preferences and the conversion prices of our cumulative convertible preferred stock:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
Shares outstanding as of January 1, 2014 and 2013 and June 30, 2014 and 2013 (in thousands)	1,497	1,100	2,559	2,096
Liquidation preference per share	$1,000	$1,000	$100	$100
Conversion price per share[a]	$25.2617	$26.1412	$40.9011	$36.2077

(a) As a result of the spin-off of our oilfield services business, conversion price adjustments were made as of the distribution date to give effect to the dividend of SSE common stock and cash dividends paid on our common stock.

Dividends

Dividends declared on our common stock and preferred stock are reflected as adjustments to retained earnings to the extent a surplus of retained earnings will exist after giving effect to the dividends. To the extent retained earnings are insufficient to fund the distributions, such payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

Dividends on our outstanding preferred stock are payable quarterly. We may pay dividends on our 5.00% Cumulative Convertible Preferred Stock (Series 2005B) and our 4.50% Cumulative Convertible Preferred Stock in cash, common stock or a combination thereof, at our option. Dividends on both series of our 5.75% Cumulative Convertible Non-Voting Preferred Stock are payable only in cash.

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Accumulated Other Comprehensive Income (Loss)

For the Current Period and the Prior Period, changes in accumulated other comprehensive income (loss) by component, net of tax, are detailed below.

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
	($ in millions)		
Balance, December 31, 2013	$(167)	$5	$(162)
Other comprehensive income before reclassifications	3	—	3
Amounts reclassified from accumulated other comprehensive income	10	(5)	5
Net other comprehensive income	13	(5)	8
Balance, June 30, 2014	$(154)	$—	$(154)

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
	($ in millions)		
Balance, December 31, 2012	$(189)	$7	$(182)
Other comprehensive income before reclassifications	—	(5)	(5)
Amounts reclassified from accumulated other comprehensive income	11	6	17
Net other comprehensive income	11	1	12
Balance, June 30, 2013	$(178)	$8	$(170)

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For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, amounts reclassified from accumulated other comprehensive income (loss), net of tax, into the condensed consolidated statements of operations are detailed below.

Details About Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income is Presented	Three Months Ended June 30, 2014	2013
		($ in millions)	
Net losses on cash flow hedges:			
Commodity contracts	Natural gas, oil and NGL revenues	$(1)	$(1)
Total reclassifications for the period, net of tax		$(1)	$(1)

Details About Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income is Presented	Six Months Ended June 30, 2014	2013
		($ in millions)	
Net losses on cash flow hedges:			
Commodity contracts	Natural gas, oil and NGL revenues	$10	$11
Investments:			
Impairment of investment	Losses on investments	—	6
Sale of investment	Net gain on sale of investment	(5)	—
Total reclassifications for the period, net of tax		$5	$17

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our natural gas and oil assets in our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including indebtedness under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and the existing wells within an area of mutual interest in the plays between the top of the Tonkawa and the top of the Big Lime formations covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 future net wells to be drilled on the contributed play leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK C-T limited liability company agreement (the CHK C-T LLC Agreement), as the holder of all the common shares and the sole managing member of CHK C-T, we maintain voting and managerial control of CHK C-T and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $225 million to the ORRI obligation and $1.025 billion to the preferred shares based on estimates of fair values. The remaining ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheets. Pursuant to the CHK C-T LLC Agreement, CHK C-T is required to retain an amount of cash equal to the next two quarters of preferred dividend payments and, until December 31, 2013, it was also required to retain an amount of cash equal to its projected operating funding shortfall for the next six months. The amount reserved, approximately $38 million as of June 30, 2014 and December 31, 2013, was reflected as restricted cash on our condensed consolidated balance sheets.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. As the managing member of CHK C-T, we may, at our sole discretion and election at any time after March 31, 2014, distribute certain excess cash of CHK C-T, as determined in accordance with the CHK C-T LLC Agreement. Any such optional distribution of excess cash is allocated 75% to the preferred shares (which is applied toward redemption of the preferred shares) and 25% to the common shares unless we have not met our drilling commitment at such time, in which case an optional distribution would be allocated 100%

to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, in accordance with the CHK C-T LLC Agreement, cause CHK C-T to redeem all or a portion of the CHK C-T preferred shares for cash. The preferred shares may be redeemed at a valuation equal to the greater of a 9% internal rate of return or a return on investment of 1.35x, in each case inclusive of dividends paid through redemption at the rate of 6% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to March 31, 2019, the optional redemption valuation will increase to provide a 15% internal rate of return to the investors. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of June 30, 2014 and December 31, 2013, the redemption price and the liquidation preference were each approximately $1,215 and $1,245, respectively, per preferred share.

We initially committed to drill and complete, for the benefit of CHK C-T in the area of mutual interest, a minimum of 37.5 net wells per six-month period through 2013, inclusive of wells drilled in 2012, and 25 net wells per six-month period in 2014 through 2016, up to a minimum cumulative total of 300 net wells. In April 2014, the drilling commitment was amended to require us only to drill and complete 12.5 net wells in each of the six-month periods ending June 30, 2014 and December 31, 2014. If we fail to meet the then-current cumulative drilling commitment in any six-month period, any optional cash distributions would be distributed 100% to the investors. If we fail to meet the then-current cumulative drilling commitment in two consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would increase by 3% per annum. In addition, if we fail to meet the then-current cumulative drilling commitment in four consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would be increased by an additional 3% per annum. Any such increase in the internal rate of return would be effective only until the end of the first succeeding six-month period in which we have met our then-current cumulative drilling commitment. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. Under the development agreement, approximately 7 and 49 qualified net wells were added in the Current Period and the Prior Period, respectively. Through June 30, 2014, we had met all current drilling commitments associated with the CHK C-T transaction.

The CHK C-T investors' right to receive, proportionately, a 3.75% ORRI in the contributed wells and up to 1,000 future net wells on our contributed leasehold is subject to an increase to 5% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs from 2012 through the first quarter of 2025. However, in no event would we be required to deliver to investors more than a total ORRI of 3.75% in existing wells and 1,000 future net wells. If at any time CHK C-T holds fewer net acres than would enable us to drill all then-remaining net wells on 160-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs. CHK C-T retains the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs once we have drilled a minimum of 867 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. We had met our ORRI conveyance commitment as of December 31, 2013, but we do not anticipate meeting the 2014 ORRI conveyance commitment.

As of June 30, 2014 and December 31, 2013, $1.015 billion of noncontrolling interests on our condensed consolidated balance sheets were attributable to CHK C-T. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, income of $19 million, $19 million, $38 million and $38 million, respectively, was attributable to the noncontrolling interests of CHK C-T.

Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale natural gas and oil assets. CHK Utica is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including indebtedness under our indentures. In exchange for all of the common shares of CHK Utica, we contributed to CHK Utica approximately 700,000 net acres of leasehold and the existing wells within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% ORRI in 1,500 net wells to be drilled on certain of our Utica Shale leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK Utica limited liability company agreement (the CHK Utica LLC Agreement), as the holder of all the common shares and the sole managing member of CHK Utica, we maintain voting and managerial control of CHK Utica and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $300 million to the ORRI obligation and $950 million to the preferred shares based on estimates of fair values. The remaining ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheets. Pursuant to the CHK Utica LLC Agreement, CHK Utica is required to retain a cash balance equal to the next two quarters of preferred dividend payments. The amount reserved for paying such dividends, approximately $37 million as of June 30, 2014 and December 31, 2013, was reflected as restricted cash on our condensed consolidated balance sheets. In addition, pursuant to the CHK Utica LLC Agreement, with respect to any divestiture proceeds as defined by the agreement, CHK Utica is required to separately account for, and dedicate all of such divestiture proceeds to either (i) capital expenditures made by CHK Utica or (ii) the redemption of CHK Utica preferred shares.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 7% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. As the managing member of CHK Utica, we may, at our sole discretion and election at any time after December 31, 2013, distribute certain excess cash of CHK Utica, as determined in accordance with the CHK Utica LLC Agreement. Any such optional distribution of excess cash is allocated 70% to the preferred shares (which is applied toward redemption of the preferred shares) and 30% to the common shares. We may also, at our sole discretion and election, in accordance with the CHK Utica LLC Agreement, cause CHK Utica to redeem the CHK Utica preferred shares for cash, in whole or in part. The preferred shares may be redeemed at a valuation equal to the greater of a 10% internal rate of return or a return on investment of 1.4x, in each case inclusive of dividends paid at the rate of 7% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to October 31, 2018, the optional redemption valuation will increase to provide the investors the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of June 30, 2014 and December 31, 2013, the redemption price and the liquidation preference were each approximately $1,217 and $1,252, respectively, per preferred share.

We have committed to drill and complete, for the benefit of CHK Utica in the area of mutual interest, a minimum of 50 net wells per year from 2012 through 2016, up to a minimum cumulative total of 250 net wells. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. If we fail to meet the then-current drilling commitment in any year, we must pay CHK Utica $5 million for each well we are short of such drilling commitment. CHK Utica also receives its proportionate share of the benefit of the drilling carry associated with our joint venture with Total in the Utica Shale. See Note 10 for further discussion of the joint venture. Under the development agreement, approximately 60 and 57 qualified net wells were added in the Current Period and the Prior Period, respectively. Through June 30, 2014, we had met all current drilling commitments associated with the CHK Utica transaction.

The CHK Utica investors' right to receive, proportionately, a 3% ORRI in the first 1,500 net wells drilled on our Utica Shale leasehold is subject to an increase to 4% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs from 2012 through 2023. However, in no event would we be required to deliver to investors more than a total ORRI of 3% in 1,500 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 150-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs once we have drilled a minimum of 1,300 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. Because we did not meet our ORRI commitment in 2012, the ORRI increased to 4% for wells earned in 2013, and the ultimate number of wells in which we must assign an interest will be reduced accordingly. We met the 2013 ORRI conveyance commitment as of December 31, 2013 and through June 30, 2014, we were on target to meet the 2014 ORRI conveyance commitments associated with the CHK Utica transaction.

As of June 30, 2014 and December 31, 2013, $807 million of noncontrolling interests on our condensed consolidated balance sheets was attributable to CHK Utica. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, income of approximately $19 million, $20 million, $37 million and $42 million, respectively, was attributable to the noncontrolling interests of CHK Utica.

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On July 29, 2014, we repurchased all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders. See Note 20 for additional information on this repurchase.

Chesapeake Granite Wash Trust. In November 2011, Chesapeake Granite Wash Trust (the “Trust”) sold 23,000,000 common units representing beneficial interests in the Trust at a price of $19.00 per common unit in its initial public offering. The common units are listed on the New York Stock Exchange and trade under the symbol “CHKR”. We own 12,062,500 common units and 11,687,500 subordinated units, which in the aggregate represent an approximate 51% beneficial interest in the Trust. The Trust has a total of 46,750,000 units outstanding.

In connection with the initial public offering of the Trust, we conveyed royalty interests to the Trust that entitle the Trust to receive (i) 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) that we receive from the production of hydrocarbons from 69 producing wells, and (ii) 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) in 118 development wells that have been or will be drilled on approximately 45,400 gross acres (29,000 net acres) in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma. Pursuant to the terms of a development agreement with the Trust, we are obligated to drill, or cause to be drilled, the development wells at our own expense prior to June 30, 2016, and the Trust will not be responsible for any costs related to the drilling of the development wells or any other operating or capital costs of the Trust properties. In addition, we granted to the Trust a lien on our remaining interests in the undeveloped properties that are subject to the development agreement in order to secure our drilling obligation to the Trust, although the maximum amount that may be recovered by the Trust under such lien could not exceed $263 million initially and is proportionately reduced as we fulfill our drilling obligation over time. As of June 30, 2014 and 2013, we had drilled or caused to be drilled approximately 93 and 73 development wells, respectively, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $55 million and $102 million, respectively.

The subordinated units we hold in the Trust are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is not less than the applicable subordination threshold for such quarter. If there is not sufficient cash to fund such a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. The distribution made with respect to the subordinated units to Chesapeake was either reduced or eliminated for each of the most recent seven quarters of distributions paid. In exchange for agreeing to subordinate a portion of our Trust units, and in order to provide additional financial incentive to us to satisfy our drilling obligation and perform operations on the underlying properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on the Trust units in any quarter exceeds the applicable incentive threshold for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following our satisfaction of our drilling obligation with respect to the development wells, the subordinated units will automatically convert into common units on a one-for-one basis and our right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share in the Trust’s distributions on a pro rata basis.

For the Current Period and the Prior Period, the Trust declared and paid the following distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
December 2013 - February 2014	May 30, 2014	$0.6454	$—

September 2013 - November 2013	March 3, 2014	$0.6624	$—
December 2012 - February 2013	May 31, 2013	$0.6900	$0.3010
September 2012 - November 2012	March 1, 2013	$0.6700	$0.3772

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We have determined that the Trust is a variable interest entity (VIE) and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our condensed consolidated financial statements. As of June 30, 2014 and December 31, 2013, $293 million and $314 million, respectively, of noncontrolling interests on our condensed consolidated balance sheets were attributable to the Trust. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, income of approximately $2 million, $7 million, $7 million and $12 million, respectively, was attributable to the Trust's noncontrolling interests in our condensed consolidated statements of operations. See Note 12 for further discussion of VIEs.

Wireless Seismic, Inc. We have a controlling 52% equity interest in Wireless Seismic, Inc. (Wireless), a privately owned company engaged in research, development and production of wireless seismic systems and related technology that deliver seismic information obtained from standard geophones in real time to laptop and desktop computers. As of June 30, 2014 and December 31, 2013, $7 million and $9 million, respectively, of noncontrolling interests on our condensed consolidated balance sheets were attributable to Wireless. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, losses of $1 million, $1 million, $2 million and $2 million, respectively, were attributable to noncontrolling interests of Wireless in our condensed consolidated statements of operations.

8. Share-Based Compensation

Chesapeake's share-based compensation program consists of restricted stock, stock options and performance share units (PSUs) granted to employees and restricted stock granted to non-employee directors under our long term incentive plans. The restricted stock and stock options are equity-classified awards and the PSUs and performance bonuses are liability-classified awards.

Equity-Classified Awards

Restricted Stock. We grant restricted stock to employees and non-employee directors. Restricted stock vests over a minimum of three years and the holder receives dividends on unvested shares. A summary of the changes in unvested shares of restricted stock during the Current Period is presented below.

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2014	13,400	$23.38
Granted	4,754	$26.11
Vested	(2,623)	$23.00
Forfeited	(2,706)	$29.27
Unvested shares as of June 30, 2014	12,825	$23.23

The aggregate intrinsic value of restricted stock that vested during the Current Period was approximately $70 million based on the stock price at the time of vesting.

As of June 30, 2014, there was $191 million of total unrecognized compensation expense related to unvested restricted stock. The expense is expected to be recognized over a weighted average period of approximately 2.4 years.

The vesting of certain restricted stock grants may result in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Quarter and the Current Period, we recognized excess tax benefits related to restricted stock of a nominal amount and $3 million, respectively, and during the Prior Quarter and the Prior Period we recognized reductions in tax benefits related to restricted stock of $2 million and $12 million, respectively. Each adjustment was recorded to additional paid-in capital and deferred income taxes.

Stock Options. In the Current Period and the Prior Period, we granted members of senior management stock options that vest ratably over a three-year period. In January 2013, we also granted retention awards to certain officers of stock options that vest one-third on each of the third, fourth and fifth anniversaries of the grant date. Each stock option award has an exercise price equal to the closing price of the Company’s common stock on the grant date. Outstanding options generally expire ten years from the date of grant.

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We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The expected life of an option is determined using the "simplified method", as there is no adequate historical exercise behavior available. Volatility assumptions are estimated based on an average of historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account the Company's current dividend policy, over the expected life of the option. The Company used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in the Current Period:

Expected option life - years	5.9	
Volatility	48.63	%
Risk-free interest rate	1.93	%
Dividend yield	1.33	%

The following table provides information related to stock option activity during the Current Period:

	Number of Shares Underlying Options		Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)]
	(in thousands)				($ in millions)
Outstanding at January 1, 2014	5,268		$19.28	6.66	$41
Granted	994		$24.43		
Exercised	(1,309	)	$18.75		$11
Expired	(19	)	$18.97		
Forfeited	(262	)	$20.30		
Outstanding at June 30, 2014	4,672		$19.60	7.90	$54
Exercisable at June 30, 2014	1,106		$18.55	6.97	$14

(a) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock exceeds the exercise price of the option.

As of June 30, 2014, there was $16 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.2 years.

The vesting of certain stock option grants may result in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of a nominal amount, $0, a nominal amount and $0, respectively. Each adjustment was recorded to additional paid-in capital and deferred income taxes.

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Restricted Stock and Stock Option Compensation. We recognized the following compensation costs related to restricted stock and stock options during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
General and administrative expenses	$11	$15	$24	$35
Natural gas and oil properties	9	12	16	32
Natural gas, oil and NGL production expenses	5	6	8	12
Marketing, gathering and compression expenses	1	1	3	4
Oilfield services expenses	3	2	5	5
Total	$29	$36	$56	$88

Liability-Classified Awards

Performance Share Units. In 2012, 2013 and 2014, we granted PSUs to senior management that settle in cash at the end of their respective performance periods and vest ratably over their respective terms. The 2012 awards were granted in one-, two- and three-year tranches and are settled in cash on the first, second and third anniversary dates of the awards, and the 2013 and 2014 awards are settled in cash on the third anniversary of the awards. The ultimate amount earned is based on achievement of performance metrics established by the Compensation Committee of the Board of Directors, which include relative and absolute total shareholder return (TSR) and, for certain of the awards, the achievement of operational performance goals such as production and proved reserve growth.

For PSUs granted in 2012, each of the TSR and operational payout components can range from 0% to 125% resulting in a maximum total payout of 250%. For PSUs granted in 2013, the TSR component can range from 0% to 125% and each of the two operational components can range from 0% to 62.5%; however, the maximum total payout is capped at 200%. For PSUs granted in 2014, the TSR component can range from 0% to 200%, with no operational components. For the 2013 and 2014 PSUs, the payout percentage is capped at 100% if the Company’s absolute TSR is less than zero. The PSU grants are recognized quarterly and valued based on the 20-day average stock price multiplied by the current estimate of the performance units that will be allocated upon vesting. The number of units allocated is dependent upon the Company’s estimates of the underlying performance measures. For the 2014 awards, the Company utilized the Monte Carlo simulation for the TSR performance measure, and used the following assumptions to determine the grant date fair value of the PSUs granted in the Current Period:

Volatility	41.37	%
Risk-free interest rate	0.76	%
Dividend yield for value of awards	1.36	%

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The following table presents a summary of our PSU awards as of June 30, 2014:

	Units	Fair Value as of Grant Date	Fair Value	Liability for Vested Amount
		($ in millions)		
2012 Awards [a]				
Payable 2015	884,507	$23	$31	$31
2013 Awards				
Payable 2016	1,701,941	$35	$66	$59
2014 Awards				
Payable 2017	658,059	$17	$20	$9

(a) In the Current Period and the Prior Period, we paid $11 million and $2 million, respectively, related to 2012 PSU awards.

PSU Compensation. We recognized the following compensation costs related to PSUs during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
Natural gas and oil properties	$2	$1	$3	$4
General and administrative expenses	11	4	10	9
Marketing, gathering and compression expenses	1	—	1	2
Total	$14	$5	$14	$15

Effects of the Spin-off on Share Based-Compensation

The employee matters agreement (see Note 2) addresses the treatment of holders of Chesapeake stock options, restricted stock and performance share units. Unvested equity-based compensation awards held by COO employees were canceled and replaced with new awards of SSE, and unvested equity-based compensation awards held by Chesapeake employees were adjusted to account for the spin-off, each as of the spin-off date. The employee matters agreement provides that employees of SSE will no longer participate in benefit plans sponsored or maintained by Chesapeake. In addition, the employee matters agreement provides that each party will be responsible for the compensation of its current employees and for all liabilities relating to its former employees.

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9. Derivative and Hedging Activities

Chesapeake uses commodity derivative instruments to secure attractive pricing and margins on expected production, to reduce its exposure to fluctuations in future commodity prices and to protect its expected operating cash flow against significant market movements or volatility. Chesapeake also uses derivative instruments to mitigate a portion of its exposure to interest rate and foreign currency exchange rate fluctuations. All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

Natural Gas and Oil Derivatives

As of June 30, 2014 and December 31, 2013, our natural gas and oil derivative instruments consisted of the following types of instruments:

- Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- Swaptions: Chesapeake sells call swaptions in exchange for a premium that allows a counterparty, on a specific date, to enter into a fixed-price swap for a certain period of time.
- Basis Protection Swaps: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

The estimated fair values of our natural gas and oil derivative instrument assets (liabilities) as of June 30, 2014 and December 31, 2013 are provided below.

	June 30, 2014		December 31, 2013	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	293	$(75)	448	$(23)
Three-way collars	335	(27)	288	(7)
Collars	22	4	—	—
Call options	193	(195)	193	(210)
Call swaptions	—	—	12	—
Basis protection swaps	106	15	68	3
Total natural gas	949	(278)	1,009	(237)
Oil (mmbbl):				
Fixed-price swaps	18.3	(146)	25.3	(50)
Three-way collars	4.4	(12)	—	—
Call options	38.9	(320)	42.5	(265)
Basis protection swaps	0.2	1	0.4	1

Total oil	61.8	(477)	68.2	(314)
Total estimated fair value		$(755)		$(551)

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We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. See further discussion below under Effect of Derivative Instruments - Accumulated Other Comprehensive Income (Loss).

Interest Rate Derivatives

As of June 30, 2014 and December 31, 2013, our interest rate derivative instruments consisted of swaps. We enter into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.

The notional amount of our interest rate derivative liabilities as of June 30, 2014 and December 31, 2013 was $1.950 billion and $2.250 billion, respectively. The estimated fair value of our interest rate derivative liabilities as of June 30, 2014 and December 31, 2013 was $48 million and $98 million, respectively.

We have terminated certain fair value hedges related to senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next six years, we will recognize $10 million in net gains related to such transactions.

Foreign Currency Derivatives

We are party to cross currency swaps to mitigate our exposure to foreign currency exchange rate fluctuations that may result from the €344 million principal amount of our euro-denominated senior notes. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Under the terms of the cross currency swaps we currently hold, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we will pay the counterparties $459 million. The swaps are designated as cash flow hedges and, because they are entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value do not impact earnings. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as an asset of $6 million as of June 30, 2014. The euro-denominated debt in long-term debt has been adjusted to $471 million as of June 30, 2014 using an exchange rate of $1.3692 to €1.00.

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Effect of Derivative Instruments – Condensed Consolidated Balance Sheets
The following table presents the fair value and location of each classification of derivative instrument included in the condensed consolidated balance sheets as of June 30, 2014 and December 31, 2013 on a gross basis and after same-counterparty netting:

	June 30, 2014		
Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
	($ in millions)		
Commodity Contracts			
Short-term derivative asset	$56	$(55)	$1
Long-term derivative asset	3	(3)	—
Short-term derivative liability	(469)	55	(414)
Long-term derivative liability	(345)	3	(342)
Total commodity contracts	(755)	—	(755)
Interest Rate Contracts			
Short-term derivative liability	(1)	—	(1)
Long-term derivative liability	(47)	—	(47)
Total interest rate contracts	(48)	—	(48)
Foreign Currency Contracts[a]			
Long-term derivative asset	6	—	6
Total foreign currency contracts	6	—	6
Total Derivatives	$(797)	$—	$(797)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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	December 31, 2013		
Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
	($ in millions)		
Commodity Contracts			
Short-term derivative asset	$29	$(29)	$—
Long-term derivative asset	11	(9)	2
Short-term derivative liability	(231)	29	(202)
Long-term derivative liability	(362)	9	(353)
Total commodity contracts	(553)	—	(553)
Interest Rate Contracts			
Short-term derivative liability	(6)	—	(6)
Long-term derivative liability	(92)	—	(92)
Total interest rate contracts	(98)	—	(98)
Foreign Currency Contracts[a]			
Long-term derivative asset	2	—	2
Total foreign currency contracts	2	—	2
Total Derivatives	$(649)	$—	$(649)

(a) Designated as cash flow hedging instruments.

As of June 30, 2014 and December 31, 2013, we did not have any cash collateral balances for these derivatives.

Effect of Derivative Instruments – Condensed Consolidated Statements of Operations

The components of natural gas, oil and NGL sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
Natural gas, oil and NGL sales	$1,917	$1,869	$4,065	$3,464
Gains (losses) on undesignated natural gas, oil and NGL derivatives	(210)	535	(574)	412
Gains (losses) on terminated cash flow hedges	(3)	2	(20)	(18)
Total natural gas, oil and NGL sales	$1,704	$2,406	$3,471	$3,858

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
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The components of interest expense for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
Interest expense on senior notes	$184	$194	$364	$380
Interest expense on term loans	7	29	36	58
Amortization of loan discount, issuance costs and other	16	30	35	48
Interest expense on credit facilities	9	11	17	22
Gains on terminated fair value hedges	(1)	(2)	(2)	(3)
(Gains) losses on undesignated interest rate derivatives	(33)	52	(51)	57
Capitalized interest	(155)	(210)	(333)	(438)
Total interest expense	$27	$104	$66	$124

Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)

A reconciliation of the changes in accumulated other comprehensive income (loss) in our condensed consolidated statements of stockholders' equity related to our cash flow hedges is presented below.

	Three Months Ended June 30,			
	2014		2013	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(247)	$(153)	$(287)	$(178)
Net change in fair value	1	—	2	1
Gains (losses) reclassified to income	3	(1)	(1)	(1)
Balance, end of period	$(243)	$(154)	$(286)	$(178)

	Six Months Ended June 30,			
	2014		2013	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(269)	$(167)	$(304)	$(189)
Net change in fair value	6	3	—	—
Losses reclassified to income	20	10	18	11
Balance, end of period	$(243)	$(154)	$(286)	$(178)

Approximately $150 million of the $154 million of accumulated other comprehensive loss as of June 30, 2014 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. These amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of June 30, 2014, we expect to transfer approximately $25 million of net loss included in accumulated other comprehensive income to net income during the next 12 months. The remaining amounts will be transferred by December 31, 2022.

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Credit Risk Considerations

Over-the-counter traded derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment-grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of June 30, 2014, our natural gas, oil and interest rate derivative instruments were spread among 17 counterparties.

Hedging Facility

Our secured commodity hedging facility with 18 counterparties provides approximately 1.063 bboe of hedging capacity for natural gas, oil and NGL price derivatives and 1.063 bboe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion. The facility is secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times at semi-annual collateral redetermination dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures, term loan and equipment master lease agreements. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain requirements are met including maintaining specified collateral coverage ratios as well as maintaining credit ratings with either of the designated rating agencies at or above current levels. The counterparties' obligations under the facility must be secured by cash or short-term U.S. treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. As of June 30, 2014, we had hedged under the facility 199 mmboe of our future production with price derivatives and 18 mmboe with basis derivatives.

Fair Value

The fair value of most of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are compared to the values given by our counterparties for reasonableness. Since natural gas, oil, interest rate and cross currency swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. Derivatives are also subject to the risk that either party to a contract will be unable to meet its obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

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The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2014 and December 31, 2013:

As of June 30, 2014	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Derivative Assets (Liabilities):				
Commodity assets	$—	$38	$22	$60
Commodity liabilities	—	(244)	(572)	(816)
Interest rate liabilities	—	(48)	—	(48)
Foreign currency assets	—	6	—	6
Total derivatives	$—	$(248)	$(550)	$(798)

As of December 31, 2013	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Derivative Assets (Liabilities):				
Commodity assets	$—	$25	$15	$40
Commodity liabilities	—	(100)	(493)	(593)
Interest rate liabilities	—	(98)	—	(98)
Foreign currency assets	—	2	—	2
Total derivatives	$—	$(171)	$(478)	$(649)

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A summary of the changes in the fair values of Chesapeake's financial assets (liabilities) classified as Level 3 during the Current Period and the Prior Period is presented below.

	Derivatives Commodity	Interest Rate
	($ in millions)	
Beginning Balance as of January 1, 2014	$(478)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	(173)	—
Total purchases, issuances, sales and settlements:		
Settlements	105	—
Transfers[(b)]	(4)	—
Ending Balance as of June 30, 2014	$(550)	$—
Beginning Balance as of January 1, 2013	$(1,016)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	362	(1)
Total purchases, issuances, sales and settlements:		
Sales	—	1
Settlements	60	—
Ending Balance as of June 30, 2013	$(594)	$—

(a)

	Natural Gas, Oil and NGL Sales		Interest Expense	
	2014	2013	2014	2013
	($ in millions)			
Total gains (losses) included in earnings for the period	$(173)	$362	$—	$(1)
Change in unrealized gains (losses) related to assets still held at reporting date	$(133)	$353	$—	$—

(b) The values related to basis swaps were transferred from Level 3 to Level 2 as a result of our ability to begin using data readily available in the public market to corroborate our estimated fair values.

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of natural gas and oil, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts. For example, an increase (decrease) in the forward prices and volatility of natural gas and oil prices decreases (increases) the fair value of natural gas and oil derivatives and adverse changes to our counterparties' creditworthiness decreases the fair value of our derivatives.

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value June 30, 2014[(a)] ($ in millions)
Oil trades	Oil price volatility curves	9.12% - 18.73%	14.63%	$(332)
Natural gas trades	Natural gas price volatility curves	19.54% - 38.70%	24.43%	$(218)

(a) Fair value is based on an estimate derived from option models.

10. Natural Gas and Oil Property Divestitures

During the Current Period and the Prior Period, excluding proceeds received from selling additional interests in our joint venture leasehold described under Joint Ventures below, we received proceeds of approximately $240 million and $815 million, respectively, related to divestitures of noncore natural gas and oil properties.

Under full cost accounting rules, we have accounted for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss as the sales have not involved a significant change in proved reserves or significantly altered the relationship between costs and proved reserves.

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Joint Ventures

As of June 30, 2014, we had entered into eight significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in eight different resource plays and received cash of $8.0 billion and commitments by our counterparties to pay our share of future drilling and completion costs of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all drilling, completion and operations, the majority of leasing and, in certain transactions, marketing activities for the project. The carries paid by a joint venture partner are for a specified percentage of our drilling and completion costs. In addition, a joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner. We bill our joint venture partners for their drilling carries at the same time we bill them and other joint working interest owners for their share of drilling costs. For accounting purposes, initial cash proceeds from these joint venture transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. The transactions are detailed below.

Primary Play	Joint Venture Partner[a]	Joint Venture Date	Interest Sold	Initial Proceeds[b]		Total Drilling Carries		Total Initial Proceeds and Drilling Carries	Drilling Carries Remaining[c]
				($ in millions)					
Mississippi Lime	Sinopec	June 2013	50.0%	$949	(d)	$—		$949	$—
Utica	TOT	December 2011	25.0%	610		1,422	(e)	2,032	347
Niobrara	CNOOC	February 2011	33.3%	570		697	(f)	1,267	26
Eagle Ford	CNOOC	November 2010	33.3%	1,120		1,080		2,200	—
Barnett	TOT	January 2010	25.0%	800		1,403		2,203	—
Marcellus	STO	November 2008	32.5%	1,250		2,125		3,375	—
Fayetteville	BP	September 2008	25.0%	1,100		800		1,900	—
Haynesville & Bossier	FCX	July 2008	20.0%	1,650		1,508		3,158	—
				$8,049		$9,035		$17,084	$373

(a) Joint venture partners are Sinopec International Petroleum Exploration and Production (Sinopec), Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Freeport-McMoRan Copper & Gold (FCX), formerly known as Plains Exploration & Production Company.
(b) Excludes closing and post-closing adjustments.
(c) As of June 30, 2014.
(d) Excludes $71 million of net proceeds (or 7% of the total transaction) expected to be received pursuant to certain post-closing adjustments and approximately $90 million received at closing for closing adjustments.
(e) The Utica drilling carry covers 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. We expect to fully utilize this drilling carry commitment prior to expiration.
(f) The Niobrara drilling carry covers 67% of our drilling and completion costs for Niobrara wells drilled and must be used by December 2014. We expect to fully utilize this drilling carry commitment prior to expiration.

During the Current Period and the Prior Period, our drilling and completion costs included the benefit of approximately $357 million and $436 million, respectively, in drilling and completion carries paid by our joint venture partners.

During the Current Period and the Prior Period, we sold interests in additional leasehold we acquired in the Marcellus, Barnett, Utica, Haynesville, Eagle Ford, Mid-Continent and Niobrara Shale plays to our joint venture partners for approximately $8 million and $39 million, respectively.

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Volumetric Production Payments

From time to time, we have sold certain of our producing assets located in more mature producing regions through the sale of VPPs. A VPP is a limited-term overriding royalty interest in natural gas and oil reserves that (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered. For all of our VPP transactions, we have novated hedges to each of the respective VPP buyers and such hedges covered all VPP volumes sold. If contractually scheduled volumes exceed the actual volumes produced from the VPP wellbores that are attributable to the ORRI conveyed, either the shortfall will be made up from future production from these wellbores (or, at our option, from our retained interest in the wellbores) through an adjustment mechanism, or the initial term of the VPP will be extended until all scheduled volumes, to the extent produced, are delivered from the VPP wellbores to the VPP buyer. We retain drilling rights on the properties below currently producing intervals and outside of producing wellbores.

As the operator of the properties from which the VPP volumes have been sold, we bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining our full cost ceiling test for impairment purposes and in determining our standardized measure. Pursuant to SEC guidelines, the estimates used for purposes of determining the cost center ceiling and the standardized measure are based on current costs. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all.

For accounting purposes, cash proceeds from the sale of VPPs were reflected as a reduction of natural gas and oil properties with no gain or loss recognized, and our proved reserves were reduced accordingly. We have also committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

Our outstanding VPPs consist of the following:

				Volume Sold			
VPP #	Date of VPP	Location	Proceeds	Natural Gas	Oil	NGL	Total
			($ in millions)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	March 2012	Anadarko Basin Granite Wash	$744	87	3.0	9.2	160
9	May 2011	Mid-Continent	853	138	1.7	4.8	177
8	September 2010	Barnett Shale	1,150	390	—	—	390
6	February 2010	East Texas and NW Louisiana	180	44	0.3	—	46

5	August 2009	South Texas	370	67	0.2	—	68
4	December 2008	Anadarko and Arkoma Basins	412	95	0.5	—	98
3	August 2008	Anadarko Basin	600	93	—	—	93
2	May 2008	Texas, Oklahoma and Kansas	622	94	—	—	94
1	December 2007	Kentucky and West Virginia	1,100	208	—	—	208
			$6,031	1,216	5.7	14.0	1,334

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The volumes produced on behalf of our VPP buyers for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period were as follows:

	Three Months Ended June 30, 2014				Three Months Ended June 30, 2013			
VPP #	Natural Gas	Oil	NGL	Total	Natural Gas	Oil	NGL	Total
	(bcf)	(mbbl)	(mbbl)	(bcfe)	(bcf)	(mbbl)	(mbbl)	(bcfe)
10	2.7	103.0	329.9	5.3	3.4	141.0	379.0	6.5
9	3.9	47.5	103.9	4.8	4.3	54.2	115.4	5.3
8	15.2	—	—	15.2	17.3	—	—	17.3
6	1.1	6.0	—	1.1	1.2	6.0	—	1.2
5	1.7	6.0	—	1.7	1.9	6.2	—	1.9
4	2.3	12.2	—	2.3	2.6	13.8	—	2.7
3	1.8	—	—	1.8	2.0	—	—	2.0
2	1.6	—	—	1.6	2.6	—	—	2.6
1	3.4	—	—	3.4	3.6	—	—	3.6
	33.7	174.7	433.8	37.2	38.9	221.2	494.4	43.1

	Six Months Ended June 30, 2014				Six Months Ended June 30, 2013			
VPP #	Natural Gas	Oil	NGL	Total	Natural Gas	Oil	NGL	Total
	(bcf)	(mbbl)	(mbbl)	(bcfe)	(bcf)	(mbbl)	(mbbl)	(bcfe)
10	5.5	212.0	675.1	10.8	7.0	295.0	786.7	13.5
9	7.9	96.5	210.4	9.7	8.7	110.4	234.2	10.8
8	30.9	—	—	30.9	35.3	—	—	35.3
6	2.2	12.0	—	2.3	2.4	12.0	—	2.4
5	3.4	12.3	—	3.5	3.9	12.2	—	3.9
4	4.6	24.6	—	4.7	5.2	28.0	—	5.4
3	3.7	—	—	3.7	4.1	—	—	4.1
2	4.0	—	—	4.0	5.3	—	—	5.3
1	7.0	—	—	7.0	7.4	—	—	7.4
	69.2	357.4	885.5	76.6	79.3	457.6	1,020.9	88.1

The volumes remaining to be delivered on behalf of our VPP buyers as of June 30, 2014 were as follows:

		Volume Remaining as of June 30, 2014			
VPP #	Term Remaining	Natural Gas	Oil	NGL	Total
	(in months)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	92	43.1	1.5	5.3	83.9
9	80	80.8	0.9	2.1	99.2
8	14	65.7	—	—	65.7
6	67	19.2	0.1	—	20.0
5	31	13.5	—	—	13.8
4	30	19.7	0.1	—	20.3
3	61	27.4	—	—	27.4
2	58	16.0	—	—	16.0
1	102	98.4	—	—	98.4
		383.8	2.6	7.4	444.7

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
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11. Investments

A summary of our investments, including our approximate ownership percentage and carrying value as of June 30, 2014 and December 31, 2013, is presented below.

	Accounting Method	Approximate Ownership % June 30, 2014	December 31, 2013	Carrying Value June 30, 2014	December 31, 2013
				($ in millions)	
FTS International, Inc.	Equity	30%	30%	$119	$138
Sundrop Fuels, Inc.	Equity	56%	56%	133	135
Chaparral Energy, Inc.	Equity	—%	20%	—	143
Other	—	—%	—%	12	61
Total investments				$264	$477

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company which, through its subsidiaries, provides hydraulic fracturing and other services to oil and gas companies. During the Current Period, we recorded negative equity method and other adjustments, prior to intercompany profit eliminations, of $27 million for our share of FTS's net loss and recorded an accretion adjustment of $8 million related to the excess of our underlying equity in net assets of FTS over our carrying value.

As of June 30, 2014, the carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $46 million, of which $14 million was attributed to non-depreciable assets. The value attributed to depreciable assets is being accreted over the estimated useful lives of the underlying assets.

Sundrop Fuels, Inc. Sundrop Fuels, Inc. (Sundrop), based in Longmont, Colorado, is a privately held cellulosic biofuels company that is constructing a nonfood biomass-based "green gasoline" plant. In the Current Period, we recorded a $7 million charge related to our share of Sundrop's net loss and capitalized interest totaling $5 million associated with the construction of Sundrop's plant. The capitalized interest is added to the investment carrying value in excess of our underlying equity and will be amortized over the life of the plant, once it is placed into service. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $67 million.

Sold Investments

Chaparral Energy, Inc. Chaparral Energy, Inc. (Chaparral), based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties. In the Current Period, we sold all of our interest in Chaparral for net cash proceeds of $209 million. We recorded a $73 million gain related to the sale.

Clean Energy Fuels Corp. In the Prior Quarter, we sold our $100 million investment in Clean Energy convertible notes for cash proceeds of $85 million. The buyer also assumed our commitment to purchase the third and final $50 million tranche of Clean Energy convertible notes. We recorded a $15 million loss related to this sale.

Other. In the Current Period, we sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction.

In the Prior Period, we sold an equity investment for cash proceeds of $6 million and recorded a $5 million gain associated with the transaction.

12. Variable Interest Entities

We consolidate the activities of VIEs for which we are the primary beneficiary. In order to determine whether we own a variable interest in a VIE, we perform qualitative analysis of the entity's design, organizational structure, primary decision makers and relevant agreements.

Consolidated VIE

Chesapeake Granite Wash Trust. For a discussion of the formation, operations and presentation of the Trust, please see Noncontrolling Interests in Note 7. The Trust is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Trust. Our ownership in the Trust and our obligations under the development agreement and related drilling support lien constitute variable interests. We have determined that we are the primary beneficiary of the Trust because (i) we have the power to direct the activities that most significantly impact the economic performance of the Trust via our obligations to perform under the development agreement, and (ii) as a result of the subordination and incentive thresholds applicable to the subordinated units we hold in the Trust, we have the obligation to absorb losses and the right to receive residual returns that could potentially be significant to the Trust. As a result, we consolidate the Trust in our financial statements, and the common units of the Trust owned by third parties are reflected as a noncontrolling interest.

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries, and the Trust is not a guarantor of any of Chesapeake's debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake; however, we have certain obligations to the Trust through the development agreement that are secured by a drilling support lien on our retained interest in the development wells up to a specified maximum amount recoverable by the Trust, which could result in the Trust acquiring all or a portion of our retained interest in the undeveloped portion of an area of mutual interest, if we do not meet our drilling commitment. In consolidation, as of June 30, 2014, $1 million of cash and cash equivalents, $287 million of net natural gas and oil properties, $9 million of short-term derivative liabilities, $20 million of other current liabilities and $1 million of long-term derivative liabilities were attributable to the Trust. We have presented parenthetically on the face of the condensed consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

Unconsolidated VIE

Mineral Acquisition Company I, L.P. In 2012, MAC-LP, L.L.C., a wholly owned non-guarantor unrestricted subsidiary of Chesapeake, entered into a partnership agreement with KKR Royalty Aggregator LLC (KKR) to form Mineral Acquisition Company I, L.P. The purpose of the partnership is to acquire mineral interests, or royalty interests carved out of mineral interests, in oil and natural gas basins in the continental United States. We are committed to acquire for our own account (outside the partnership) 10% of any acquisition agreed upon by the partnership up to a maximum of $25 million, and the partnership will acquire the remaining 90% up to a maximum of $225 million, funded entirely by KKR, making KKR the sole equity investor. We have significant influence over the decisions made by the partnership, as we hold two of five seats on the board of directors. We will receive proportionate distributions from the partnership of any cash received from royalties in excess of expenses paid, ranging from 7% to 22.5%. The partnership is considered a VIE because KKR's control over the partnership is disproportionate to its economic interest. This VIE remains unconsolidated as the power to direct the activities of the partnership is shared between the Company and KKR. We are using the equity method to account for this investment. The carrying value of our investment was $9 million as of June 30, 2014.

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13. Other Property and Equipment

Net Gains on Sales of Fixed Assets

A summary by asset class of (gains) or losses on sales of fixed assets for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
Compressors	$(94)	$—	$(120)	$—
Gathering systems and treating plants	10	(109)	13	(179)
Oilfield services equipment	(9)	—	(7)	1
Buildings and land	1	1	1	23
Other	(1)	(1)	(2)	(3)
Total net gains on sales of fixed assets	$(93)	$(109)	$(115)	$(158)

Compressors. In the Current Quarter, we sold 337 compressors and related equipment to Exterran Partners, L.P. for approximately $362 million. We recorded a $93 million gain associated with the transaction. In the Current Period, we also sold 102 compressors and related equipment to Access Midstream Partners, L.P. for proceeds of approximately $159 million. We recorded a $24 million gain associated with the transaction.

Gathering Systems and Treating Plants. In the Prior Quarter, we sold our wholly owned subsidiary Granite Wash Midstream Gas Services, L.L.C. (GWMGS) to MarkWest Oklahoma Gas Company, L.L.C., a wholly owned subsidiary of MarkWest Energy Partners, L.P. (NYSE:MWE), for net proceeds of approximately $245 million. We recorded a $106 million gain associated with this transaction. GWMGS owned certain midstream assets in the Anadarko Basin that service the Granite Wash and Hogshooter formations. The transaction with MWE included long-term fixed fee arrangements for gas gathering, compression, treating and processing services. In the Prior Period, we also sold our interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP (NYSE:WES) for proceeds of approximately $134 million. We recorded a $56 million gain associated with this transaction.

Oilfield Services Equipment. In the Current Quarter, we sold substantially all of our crude oil hauling assets for approximately $44 million. We recorded a $23 million gain associated with the transaction. Also, during the Current Quarter, we sold 14 rigs for approximately $14 million and recorded a $14 million loss.

Buildings and Land. In the Prior Period, we recorded net losses of $23 million on sales of buildings and land located primarily in our Barnett Shale operating area.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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Assets Held for Sale

In 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. In addition, as of June 30, 2014, we were continuing to pursue the sale of various land and buildings located in the Fort Worth, Texas area. We are also pursuing the sale of certain compressors. Land and buildings are recorded under our other segment, and compressors are reported under our marketing, gathering and compression operating segment. These assets are being actively marketed, and we believe it is probable they will be sold over the next 12 months. As a result, these assets are reflected as held for sale as of June 30, 2014. Natural gas and oil properties that we intend to sell are not presented as held for sale pursuant to the rules governing full cost accounting for oil and gas properties. A summary of the assets held for sale on our condensed consolidated balance sheets as of June 30, 2014 and December 31, 2013 is detailed below.

	June 30, 2014	December 31, 2013
	($ in millions)	
Buildings and land, net of accumulated depreciation	$183	$405
Compressors, net of accumulated depreciation	64	285
Oilfield services equipment, net of accumulated depreciation	—	29
Gathering systems and treating plants, net of accumulated depreciation	—	11
Property and equipment held for sale, net	$247	$730

In March 2014, management determined that certain properties in the Fort Worth area of the Barnett Shale, previously classified as held for sale as of December 31, 2013, would be reclassified as held for use. As of December 31, 2013, management's development plan for the Barnett Shale did not contemplate the need for the underlying properties (for pad drilling in certain urban locations around Fort Worth) and the properties were marketed for sale. Management modified its development plan and consequently these properties no longer met the criteria to be classified as held for sale as of March 31, 2014. The properties were measured at the lesser of their fair value at the date of the decision not to sell or their carrying amount before being classified as held for sale. During the Current Period, we reclassified $116 million of such properties to held for use classification. There was no impact to the statement of operations related to this reclassification in the Current Period.

14. Impairments of Fixed Assets and Other

We review our long-lived assets, other than our natural gas and oil properties which are subject to quarterly full cost ceiling tests, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable and recognize an impairment loss if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. A summary of our impairments of fixed assets by asset class and other charges for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
Gathering systems and treating plants	$10	$—	$10	$—
Oilfield services equipment	3	4	23	4
Buildings and land	5	213	5	239
Other	22	14	22	15
Total impairments of fixed assets and other	$40	$231	$60	$258

Gathering Systems and Treating Plants. In the Current Quarter and the Current Period, we recorded $10 million of impairments related to certain gathering systems and treating plants. The gathering systems and treating plants are included in our marketing, gathering and compression operating segment.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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Oilfield Services Equipment. In the Current Period, we purchased 31 leased rigs and equipment from various lessors for an aggregate purchase price of $140 million. In connection with these purchases, we paid $8 million in early lease termination costs, which is included in impairments of fixed assets and other in the condensed consolidated statement of operations. We recognized an impairment loss of approximately $15 million of leasehold improvements associated with these transactions. The drilling rigs and equipment are included in our former oilfield services operating segment.

Buildings and Land. In the Prior Period, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. We recognized an impairment loss of $134 million during the Prior Quarter on these assets for the difference between the carrying amount and fair value of the assets, less the anticipated costs to sell. Given the impairment losses associated with these assets, we tested other noncore buildings and land that we own in the Oklahoma City area for recoverability. As a result of this test, we recognized an additional impairment loss in the Prior Quarter of $44 million on these assets. Due to a decrease in the estimated market prices of certain property classified as held for sale in the Fort Worth area, we recognized an additional impairment loss of $29 million in the Prior Quarter. In the Prior Period, we also recognized $26 million of impairment loss on certain of our buildings and land in the Oklahoma City area (other than our core campus) classified as assets held for sale. The impaired buildings and land are included in our other segment.

Other. Under the terms of our joint venture agreements (see Note 10), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas. In the Current Quarter, we revised our estimate of our net acreage shortfall with Total under the terms of our Barnett Shale joint venture agreement and recorded an additional $22 million charge. See Note 5 for additional discussion regarding our net acreage maintenance commitments.

Nonrecurring Fair Value Measurements. Fair value measurements for impairments on the drilling rigs and equipment discussed above were based on recent sales information for comparable rigs and equipment. As the fair value was estimated using the market approach based on recent prices from orderly sales transactions for comparable assets between market participants, the values were classified as Level 2 in the fair value hierarchy. Fair value measurements of the buildings and land discussed above were based on prices from orderly sales transaction for comparable properties between market participants, purchase offers we received from third parties and, in certain cases, discounted cash flows. As some inputs used were not observable in the market, these values were classified as Level 3 in the fair value hierarchy.

15. Restructuring and Other Termination Costs

On June 30, 2014, we completed the spin-off of our oilfield services business through a pro rata distribution of SSE common stock to holders of Chesapeake common stock. In connection with the spin-off, we incurred restructuring charges of $12 million consisting of transaction costs, stock-based compensation adjustments and debt extinguishment costs. See Note 2 for further discussion of the spin-off.

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and CEO and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Mr. McClendon’s departure from the Company was treated as a termination without cause under his employment agreement. On April 18, 2013, the Company and Mr. McClendon entered into a Founder Separation and Services Agreement, effective January 29, 2013, regarding his separation from employment and to facilitate the relationship between the Company and Mr. McClendon as joint working interest owners of oil and gas wells and acreage. In the Prior Period, we incurred charges of approximately $64 million related to Mr. McClendon’s departure.

In December 2012, Chesapeake announced that it had offered a voluntary separation program (VSP) to certain employees as part of the Company's ongoing efforts to improve efficiencies and reduce costs. The VSP was offered to approximately 275 employees who met criteria based upon a combination of age and years of Chesapeake service, and 211 accepted prior to the expiration of the offer in February 2013. We recognized the expense related to their termination benefits over their remaining service period, which resulted in $62 million of expense for the Prior Period.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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During the Prior Period, we also incurred charges of approximately $14 million related to other workforce reductions, including separations of executive officers other than the CEO. Substantially all of the restructuring and other termination costs in 2013 are in the exploration and production operating segment.
Below is a summary of our restructuring and other termination costs for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	($ in millions)			
Oilfield services spin-off costs:				
Transaction costs	$14	$—	$14	$—
Stock-based compensation adjustments for Chesapeake employees	5	—	5	—
Stock-based compensation forfeitures for SSE employees	(10)	—	(10)	—
Debt extinguishment costs	3	—	3	—
Total oilfield services spin-off costs	12	—	12	—
Termination benefits provided to Mr. McClendon:				
Salary and bonus expense	—	—	—	11
Acceleration of 2008 performance bonus clawback	—	—	—	11
Acceleration of stock-based compensation	—	—	—	22
Acceleration of performance share unit awards[(a)]	5	—	2	13
Estimated aircraft usage benefits	—	—	—	7
Total termination benefits provided to Mr. McClendon	5	—	2	64
Termination benefits provided to VSP participants:				
Salary and bonus expense	—	3	—	32
Acceleration of stock-based compensation	—	3	—	27
Other termination benefits	—	—	—	3
Total termination benefits provided to VSP participants	—	6	—	62
Other termination benefits[(a)]	16	1	12	14
Total restructuring and other termination costs	$33	$7	$26	$140

(a) The Current Quarter and Current Period amounts are primarily related to fair value adjustments to PSUs granted to former executives of the Company. For further discussion of our PSUs, see Note 8.

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16. Fair Value Measurements

Recurring Fair Value Measurements

Other Current Assets. Assets related to Company matches of employee contributions to Chesapeake's employee benefit plans are included in other current assets. The fair value of these assets is determined using quoted market prices as they consist of exchange-traded securities.

Other Current Liabilities. Liabilities related to Chesapeake's deferred compensation plan are included in other current liabilities. The fair values of these liabilities are determined using quoted market prices, as the plan consists of exchange-traded mutual funds.

Financial Assets (Liabilities). The following table provides fair value measurement information for the above-noted financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2014 and December 31, 2013:

As of June 30, 2014	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Other current assets	$57	$—	$—	$57
Other current liabilities	(58)	—	—	(58)
Total	$(1)	$—	$—	$(1)

As of December 31, 2013	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Other current assets	$80	$—	$—	$80
Other current liabilities	(82)	—	—	(82)
Total	$(2)	$—	$—	$(2)

See Note 4 for information regarding fair value of other financial instruments. See Note 9 for information regarding fair value measurement of derivatives.

Nonrecurring Fair Value Measurements

See Note 14 regarding nonrecurring fair value measurements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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17. Segment Information

As of June 30, 2014, we have two reportable operating segments, each of which is managed separately because of the nature of its operations. The exploration and production operating segment is responsible for finding and producing natural gas, oil and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of natural gas, oil and NGL. In addition, prior to the spin-off described in Note 2, our former oilfield services operating segment was responsible for drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties. Our former oilfield services segment's historical financial results for periods prior to the spin-off continue to be included in our historical financial results as a component of continuing operations as reflected in the tables below.
Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas, oil and NGL related to Chesapeake's ownership interests by the marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. Such amounts totaled $2.188 billion, $1.933 billion, $4.596 billion and $3.678 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Revenues generated by our former oilfield services operating segment for work performed for Chesapeake's exploration and production operating segment were reclassified to the full cost pool based on Chesapeake's ownership interest. Revenues reclassified totaled $274 million, $377 million, $544 million and $735 million the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. No income was recognized in our condensed consolidated statements of operations related to oilfield services performed for Chesapeake-operated wells.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

The following table presents selected financial information for Chesapeake's operating segments:

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Three Months Ended June 30, 2014:						
Revenues	$1,704	$5,355	$552	$3	$(2,462)	$5,152
Intersegment revenues	—	(2,188)	(274)	—	2,462	—
Total revenues	$1,704	$3,167	$278	$3	$—	$5,152
Income (Loss) Before Income Taxes	$410	$109	$19	$(20)	$(147)	$371
Three Months Ended June 30, 2013:						
Revenues	$2,406	$3,990	$582	$14	$(2,317)	$4,675
Intersegment revenues	—	(1,933)	(377)	(7)	2,317	—
Total revenues	$2,406	$2,057	$205	$7	$—	$4,675
Income (Loss) Before Income Taxes	$1,162	$158	$4	$(213)	$(102)	$1,009
Six Months Ended June 30, 2014:						
Revenues	$3,471	$10,777	$1,060	$30	$(5,140)	$10,198
Intersegment revenues	—	(4,596)	(544)	—	5,140	—
Total revenues	$3,471	$6,181	$516	$30	$—	$10,198
Income (Loss) Before Income Taxes	$1,098	$213	$(16)	$39	$(217)	$1,117
Six Months Ended June 30, 2013:						
Revenues	$3,858	$7,516	$1,127	$23	$(4,426)	$8,098
Intersegment revenues	—	(3,678)	(735)	(13)	4,426	—
Total revenues	$3,858	$3,838	$392	$10	$—	$8,098
Income (Loss) Before Income Taxes	$625	$272	$26	$451	$(200)	$1,174
As of June 30, 2014:						

Total Assets	$35,527	$2,334	$50	$5,283	$(2,067)	$41,127
As of December 31, 2013:						
Total Assets	$35,341	$2,430	$2,018	$5,750	$(3,757)	$41,782

18. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 4 are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries on a senior unsecured basis. Subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries are non-guarantors. Our oilfield services subsidiaries were separately capitalized and were not guarantors of our debt obligations.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of June 30, 2014 and December 31, 2013 and for the three and six months ended June 30, 2014 and 2013. Such financial information may not necessarily be indicative of our results of operations, cash flows or financial position had these subsidiaries operated as independent entities.

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CONDENSED CONSOLIDATING BALANCE SHEET
AS OF JUNE 30, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$1,371	$—	$ 117	$(26)	$1,462
Restricted cash	—	—	81	(6)	75
Other	79	2,542	181	31	2,833
Intercompany receivable, net	25,163	—	—	(25,163)	—
Total Current Assets	26,613	2,542	379	(25,164)	4,370
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost .accounting, net	—	30,786	3,083	(420)	33,449
Other property and equipment, net	—	2,309	6	—	2,315
Property and equipment held for sale, net	—	247	—	—	247
Total Property and Equipment, Net	—	33,342	3,089	(420)	36,011
LONG-TERM ASSETS:					
Other assets	113	605	28	—	746
Investments in subsidiaries and intercompany advances	1,867	(550)	—	(1,317)	—
TOTAL ASSETS	$28,593	$35,939	$ 3,496	$(26,901)	$41,127
CURRENT LIABILITIES:					
Current liabilities	$261	$5,446	$ 117	$(32)	$5,792
Intercompany payable, net	—	25,608	930	(26,538)	—
Total Current Liabilities	261	31,054	1,047	(26,570)	5,792
LONG-TERM LIABILITIES:					
Long-term debt, net	11,549	—	—	—	11,549
Deferred income tax liabilities	342	1,964	550	917	3,773
Other long-term liabilities	239	1,054	395	—	1,688
Total Long-Term Liabilities	12,130	3,018	945	917	17,010
EQUITY:					
Chesapeake stockholders' equity	16,202	1,867	1,504	(3,371)	16,202
Noncontrolling interests	—	—	—	2,123	2,123
Total Equity	16,202	1,867	1,504	(1,248)	18,325
TOTAL LIABILITIES AND EQUITY	$28,593	$35,939	$ 3,496	$(26,901)	$41,127

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
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CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$799	$—	$ 39	$(1)	$837
Restricted cash	—	—	82	(7)	75
Other	103	2,411	578	(348)	2,744
Intercompany receivable, net	25,357	—	—	(25,357)	—
Total Current Assets	26,259	2,411	699	(25,713)	3,656
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,295	3,113	185	32,593
Other property and equipment, net	—	2,360	1,452	(1)	3,811
Property and equipment held for sale, net	—	701	29	—	730
Total Property and Equipment, Net	—	32,356	4,594	184	37,134
LONG-TERM ASSETS:					
Other assets	111	1,161	96	(376)	992
Investments in subsidiaries and intercompany advances	2,361	(262)	—	(2,099)	—
TOTAL ASSETS	$28,731	$35,666	$ 5,389	$(28,004)	$41,782
CURRENT LIABILITIES:					
Current liabilities	$300	$5,227	$ 344	$(356)	$5,515
Intercompany payable, net	—	24,775	558	(25,333)	—
Total Current Liabilities	300	30,002	902	(25,689)	5,515
LONG-TERM LIABILITIES:					
Long-term debt, net	11,831	—	1,055	—	12,886
Deferred income tax liabilities	209	2,281	830	87	3,407
Other long-term liabilities	396	1,022	788	(372)	1,834
Total Long-Term Liabilities	12,436	3,303	2,673	(285)	18,127
EQUITY:					
Chesapeake stockholders' equity	15,995	2,361	1,814	(4,175)	15,995
Noncontrolling interests	—	—	—	2,145	2,145
Total Equity	15,995	2,361	1,814	(2,030)	18,140
TOTAL LIABILITIES AND EQUITY	$28,731	$35,666	$ 5,389	$(28,004)	$41,782

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED JUNE 30, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$1,469	$237	$(2)	$1,704
Marketing, gathering and compression	—	3,166	1	—	3,167
Oilfield services	—	23	499	(241)	281
Total Revenues	—	4,658	737	(243)	5,152
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	266	16	—	282
Production taxes	—	69	3	—	72
Marketing, gathering and compression	—	3,166	—	—	3,166
Oilfield services	—	22	375	(185)	212
General and administrative	—	66	24	—	90
Restructuring and other termination costs	—	30	3	—	33
Natural gas, oil and NGL depreciation, depletion and amortization	—	583	68	10	661
Depreciation and amortization of other assets	—	38	71	(30)	79
Impairment of natural gas and oil properties	—	—	38	(38)	—
Impairments of fixed assets and other	—	37	3	—	40
Net gains on sales of fixed assets	—	(85)	(8)	—	(93)
Total Operating Expenses	—	4,192	593	(243)	4,542
INCOME FROM OPERATIONS	—	466	144	—	610
OTHER INCOME (EXPENSE):					
Interest expense	(156)	(3)	(20)	152	(27)
Losses on investments	—	(19)	(5)	—	(24)
Losses on purchases of debt	(195)	—	—	—	(195)
Other income (loss)	136	33	—	(162)	7
Equity in net earnings of subsidiary	324	35	—	(359)	—
Total Other Income (Expense)	109	46	(25)	(369)	(239)
INCOME BEFORE INCOME TAXES	109	512	119	(369)	371
INCOME TAX EXPENSE	(82)	182	45	(4)	141
NET INCOME	191	330	74	(365)	230
Net income attributable to noncontrolling interests	—	—	—	(39)	(39)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	191	330	74	(404)	191
Other comprehensive income (loss)	1	(2)	—	—	(1)
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$192	$328	$74	$(404)	$190

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED JUNE 30, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$2,241	$160	$5	$2,406
Marketing, gathering and compression	—	2,051	6	—	2,057
Oilfield services	—	60	484	(332)	212
Total Revenues	—	4,352	650	(327)	4,675
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	274	14	—	288
Production taxes	—	57	2	—	59
Marketing, gathering and compression	—	2,026	2	—	2,028
Oilfield services	—	99	354	(276)	177
General and administrative	—	80	26	—	106
Restructuring and other termination costs	—	6	1	—	7
Natural gas, oil and NGL depreciation, depletion and amortization	—	589	56	—	645
Depreciation and amortization of other assets	—	46	71	(41)	76
Impairment of natural gas and oil properties	—	—	70	(70)	—
Impairments of fixed assets and other	—	224	7	—	231
Net gains on sales of fixed assets	—	(109)	—	—	(109)
Total Operating Expenses	—	3,292	603	(387)	3,508
INCOME FROM OPERATIONS	—	1,060	47	60	1,167
OTHER INCOME (EXPENSE):					
Interest expense	(278)	(42)	(21)	237	(104)
Losses on investments	—	23	—	—	23
Net gain on sales of investments	—	(10)	—	—	(10)
Losses on purchases of debt	(70)	—	—	—	(70)
Other income	228	63	(22)	(266)	3
Equity in net earnings (losses) of subsidiary	654	(64)	—	(590)	—
Total Other Income (Expense)	534	(30)	(43)	(619)	(158)
INCOME BEFORE INCOME TAXES	534	1,030	4	(559)	1,009
INCOME TAX EXPENSE (BENEFIT)	(46)	416	2	12	384
NET INCOME	580	614	2	(571)	625
Net income attributable to noncontrolling interests	—	—	—	(45)	(45)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	580	614	2	(616)	580

Other comprehensive income (loss)	2	(2)	—	—	—
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$582	$612	$2	$(616)	$580

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$3,015	$459	$(3)	$3,471
Marketing, gathering and compression	—	6,180	2	—	6,182
Oilfield services	—	40	983	(478)	545
Total Revenues	—	9,235	1,444	(481)	10,198
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	535	35	—	570
Production taxes	—	117	5	—	122
Marketing, gathering and compression	—	6,145	2	—	6,147
Oilfield services	—	54	769	(392)	431
General and administrative	—	120	49	—	169
Restructuring and other termination costs	—	23	3	—	26
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,151	129	8	1,288
Depreciation and amortization of other assets	—	78	143	(64)	157
Impairment of natural gas and oil properties	—	—	98	(98)	—
Impairments of fixed assets and other	—	37	23	—	60
Net gains on sales of fixed assets	—	(109)	(6)	—	(115)
Total Operating Expenses	—	8,151	1,250	(546)	8,855
INCOME FROM OPERATIONS	—	1,084	194	65	1,343
OTHER INCOME (EXPENSE):					
Interest expense	(347)	(3)	(42)	326	(66)
Losses on investments	—	(42)	(5)	2	(45)
Net gain on sales of investments	—	67	—	—	67
Losses on purchases of debt	(195)	—	—	—	(195)
Other income (loss)	479	(107)	1	(360)	13
Equity in net earnings of subsidiary	655	12	—	(667)	—
Total Other Income (Expense)	592	(73)	(46)	(699)	(226)
INCOME BEFORE INCOME TAXES	592	1,011	148	(634)	1,117
INCOME TAX EXPENSE	(24)	377	56	12	421
NET INCOME	616	634	92	(646)	696
Net income attributable to noncontrolling interests	—	—	—	(80)	(80)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	616	634	92	(726)	616
Other comprehensive income	3	5	—	—	8
COMPREHENSIVE INCOME	$619	$639	$92	$(726)	$624

ATTRIBUTABLE TO CHESAPEAKE

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$3,562	$288	$8	$3,858
Marketing, gathering and compression	—	3,829	9	—	3,838
Oilfield services	—	116	934	(648)	402
Total Revenues	—	7,507	1,231	(640)	8,098
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	570	25	—	595
Production taxes	—	108	4	—	112
Marketing, gathering and compression	—	3,767	5	—	3,772
Oilfield services	—	146	716	(530)	332
General and administrative	—	170	46	—	216
Restructuring and other termination costs	—	137	3	—	140
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,180	113	—	1,293
Depreciation and amortization of other assets	—	96	139	(81)	154
Impairment of natural gas and oil properties	—	—	161	(161)	—
Impairments of fixed assets and other	—	251	7	—	258
Net gains on sales of fixed assets	—	(158)	—	—	(158)
Total Operating Expenses	—	6,267	1,219	(772)	6,714
INCOME FROM OPERATIONS	—	1,240	12	132	1,384
OTHER INCOME (EXPENSE):					
Interest expense	(496)	(43)	(42)	457	(124)
Losses on investments	—	(14)	—	—	(14)
Net gain on sales of investments	—	(10)	—	—	(10)
Losses on purchases of debt	(70)	—	—	—	(70)
Other income	443	75	5	(515)	8
Equity in net earnings (losses) of subsidiary	715	(153)	—	(562)	—
Total Other Income (Expense)	592	(145)	(37)	(620)	(210)
INCOME BEFORE INCOME TAXES	592	1,095	(25)	(488)	1,174
INCOME TAX EXPENSE (BENEFIT)	(47)	474	(9)	28	446
NET INCOME	639	621	(16)	(516)	728
Net income attributable to noncontrolling interests	—	—	—	(89)	(89)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	639	621	(16)	(605)	639

Other comprehensive income	—	12	—	—	12
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$639	$633	$(16)	$(605)	$651

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
SIX MONTHS ENDED JUNE 30, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$2,134	$509	$—	$2,643
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(1,791)	(205)	—	(1,996)
Acquisitions of proved and unproved properties	—	(356)	—	—	(356)
Proceeds from divestitures of proved and unproved properties	—	247	1	—	248
Additions to other property and equipment	—	(368)	(252)	—	(620)
Other investing activities	—	858	60	26	944
Net Cash Used In Investing Activities	—	(1,410)	(396)	26	(1,780)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	140	717	—	857
Payments on credit facilities borrowings	—	(140)	(1,099)	—	(1,239)
Proceeds from issuance of senior notes, net of discount and offering costs	2,966	—	494	—	3,460
Proceeds from issuance of oilfield services term loan, net of issuance costs	—	—	394	—	394
Cash paid to purchase debt	(3,362)	—	—	—	(3,362)
Other financing activities	(193)	15	(119)	(51)	(348)
Intercompany advances, net	1,161	(739)	(422)	—	—
Net Cash Provided By (Used In) Financing Activities	572	(724)	(35)	(51)	(238)
Net increase (decrease) in cash and cash equivalents	572	—	78	(25)	625
Cash and cash equivalents, beginning of period	799	—	39	(1)	837
Cash and cash equivalents, end of period	$1,371	$—	$117	$(26)	$1,462

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
SIX MONTHS ENDED JUNE 30, 2013
($ in millions)

	Parent[(a)]	Guarantor Subsidiaries[(a)]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$1,933	$297	$(25)	$2,205
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(2,689)	(456)	—	(3,145)
Acquisitions of proved and unproved properties	—	(549)	(1)	—	(550)
Proceeds from divestitures of proved and unproved properties	—	1,834	61	—	1,895
Additions to other property and equipment	—	(316)	(190)	—	(506)
Other investing activities	—	161	440	130	731
Net Cash Used In Investing Activities	—	(1,559)	(146)	130	(1,575)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	6,013	546	—	6,559
Payments on credit facilities borrowings	—	(6,013)	(565)	—	(6,578)
Proceeds from issuance of senior notes, net of discount and offering costs	2,274	—	—	—	2,274
Cash paid to purchase debt	(1,874)	—	—	—	(1,874)
Proceeds from sales of noncontrolling interests	—	5	—	—	5
Other financing activities	(245)	(292)	16	(105)	(626)
Intercompany advances, net	272	(87)	(185)	—	—
Net Cash Provided By (Used In) Financing Activities	427	(374)	(188)	(105)	(240)
Net increase (decrease) in cash and cash equivalents	427	—	(37)	—	390
Cash and cash equivalents, beginning of period	228	—	59	—	287
Cash and cash equivalents, end of period	$655	$—	$22	$—	$677

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent. As of December 31, 2012 and June 30, 2013, $228 million and $655 million, respectively, were incorrectly presented in the Guarantor Subsidiaries column. The impact of this error was not material to any previously issued financial statements.

19. Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board (FASB) issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We adopted this standard January 1, 2014, and it did not have a material impact consolidated our financial statements.

In April 2014, the FASB issued an accounting standards update that raises the threshold for a disposal or classification as held for sale to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This accounting standards update is effective for us beginning on January 1, 2015, and it is not expected to have a material impact on our consolidated financial statements.

In May 2014, the FASB issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration the company expects to receive in the exchange. The accounting standards update is effective for us beginning January 1, 2017, and we are evaluating the impact on our consolidated financial statements.

20. Subsequent Events

On July 29, 2014, we announced that we had entered into an agreement with RKI Exploration & Production, LLC (RKI) to exchange interests in approximately 440,000 gross acres in the Powder River Basin (PRB) in southeastern Wyoming. Under the agreement, Chesapeake will convey to RKI approximately 137,000 net acres and its interest in 67 gross wells with an average working interest of approximately 22% in the northern portion of the PRB, where RKI is currently designated operator. In exchange, RKI will convey to Chesapeake approximately 203,000 net acres and its interest in 186 gross wells with an average working interest of 48% in the southern portion of the PRB, where Chesapeake is currently designated operator. In addition to the exchange, we will pay RKI $450 million in cash. The transaction, which is subject to certain closing conditions, including the receipt of third-party consents, is expected to close in August 2014. Our interest in the properties acquired from RKI is subject to reduction if applicable participation rights are exercised and other conditions, including payment to us of consideration for such participation, are fulfilled.

On July 29, 2014, we repurchased all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders for approximately $1.26 billion, or approximately $1,189 per share including accrued dividends. Pursuant to the transaction, our obligation to pay quarterly dividends to third-party preferred shareholders was eliminated. In addition, the development agreement was terminated pursuant to the transaction, which removed our obligations to drill and complete a minimum number of wells within a specified period for the benefit of CHK Utica. Our repurchase of the outstanding preferred shares in CHK Utica did not affect our obligation to deliver a 3% ORRI in 1,500 net wells on certain Utica Shale leasehold. See Note 7 for discussion of our ORRI obligation.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Financial Data

The following table sets forth certain information regarding our production volumes, natural gas, oil and natural gas liquids (NGL) sales, average sales prices received, other operating income and expenses for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net Production:				
Natural gas (bcf)	271.3	277.6	531.4	550.8
Oil (mmbbl)	10.3	10.5	20.2	19.8
NGL (mmbbl)	7.7	4.8	15.2	9.6
Oil equivalent (mmboe)[a]	63.2	61.6	124.0	121.2
Natural Gas, Oil and NGL Sales ($ in millions):				
Natural gas sales	$750	$779	$1,754	$1,352
Natural gas derivatives - realized gains (losses)[b]	(86)	(53)	(240)	(45)
Natural gas derivatives - unrealized gains (losses)[b]	113	347	(41)	68
Total natural gas sales	777	1,073	1,473	1,375
Oil sales	1,006	975	1,928	1,859
Oil derivatives - realized gains (losses)[b]	(127)	14	(210)	10
Oil derivatives - unrealized gains (losses)[b]	(113)	229	(103)	361
Total oil sales	766	1,218	1,615	2,230
NGL sales	161	115	383	253
Total NGL sales	161	115	383	253
Total natural gas, oil and NGL sales	$1,704	$2,406	$3,471	$3,858
Average Sales Price (excluding gains (losses) on derivatives):				
Natural gas ($ per mcf)	$2.76	$2.81	$3.30	$2.45
Oil ($ per bbl)	$97.49	$92.53	$95.59	$93.79
NGL ($ per bbl)	$21.03	$24.22	$25.10	$26.26
Oil equivalent ($ per boe)	$30.32	$30.36	$32.79	$28.57
Average Sales Price (including realized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$2.45	$2.62	$2.85	$2.37
Oil ($ per bbl)	$85.23	$93.81	$85.16	$94.29
NGL ($ per bbl)	$21.03	$24.22	$25.10	$26.26
Oil equivalent ($ per boe)	$26.97	$29.73	$29.16	$28.28

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Other Operating Income[(c)] ($ in millions):				
Marketing, gathering and compression net margin	$1	$29	$35	$66
Oilfield services net margin	$69	$35	$114	$70
Expenses ($ per boe):				
Natural gas, oil and NGL production	$4.46	$4.68	$4.59	$4.91
Production taxes	$1.14	$0.95	$0.99	$0.92
General and administrative[(d)]	$1.43	$1.73	$1.37	$1.78
Natural gas, oil and NGL depreciation, depletion and amortization	$10.45	$10.48	$10.39	$10.67
Depreciation and amortization of other assets	$1.25	$1.23	$1.27	$1.27
Interest expense[(e)]	$0.92	$0.85	$0.91	$0.55
Interest Expense ($ in millions):				
Interest expense	$61	$54	$119	$70
Interest rate derivatives – realized (gains) losses[(f)]	(3)	(1)	(6)	(3)
Interest rate derivatives – unrealized (gains) losses[(f)]	(31)	51	(47)	57
Total interest expense	$27	$104	$66	$124

(a) Oil equivalent is based on six mcf of natural gas to one barrel of oil or one barrel of NGL. This ratio reflects an energy content equivalency and not a price or revenue equivalency. In recent years, the price for a bbl of oil and NGL has been significantly higher than the price for six mcf of natural gas.

(b) Realized gains and losses include the following items: (i) settlements of undesignated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period production revenues, and (iii) gains and losses related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains and losses include the change in fair value of open derivatives scheduled to settle against future period production revenues offset by amounts reclassified as realized gains and losses during the period.

(c) Includes revenue and operating costs. See Depreciation and Amortization of Other Assets under Results of Operations for details of the depreciation and amortization associated with our marketing, gathering and compression and former oilfield services operating segments.

(d) Includes stock-based compensation but excludes restructuring and other termination costs.

(e) Includes the effects of realized (gains) losses from interest rate derivatives, excludes the effects of unrealized (gains) losses from interest rate derivatives and is net of amounts capitalized.

(f) Realized (gains) losses include settlements related to the current period interest accrual and the effect of (gains) losses on early-terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item. Unrealized (gains) losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Overview

Chesapeake is currently the second-largest producer of natural gas and the tenth-largest producer of liquids in the United States. We own interests in approximately 48,000 natural gas and oil wells that produced an average of approximately 695 mboe per day in the Current Quarter, net to our interest. We have a large and geographically diverse resource base of onshore U.S. unconventional natural gas and liquids assets. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas; and the Niobrara Shale and Upper Cretaceous sands in the Powder River Basin in Wyoming. Our core natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. We also own substantial marketing and compression businesses.

Our Strategy

With substantial leasehold positions in most of the premier U.S. onshore resource plays, Chesapeake is focused on finding and producing hydrocarbons in a responsible and efficient manner that seeks to maximize shareholder returns. We are committed to increasing our profitability and decreasing our financial complexity through the execution of our business strategy, which consists of two fundamental tenets: financial discipline and profitable and efficient growth from captured resources.

We are applying financial discipline to all aspects of our business, with the primary goals of balancing capital expenditures with cash flow from operations, divesting noncore assets and affiliates, achieving investment grade metrics, lowering our per unit costs, and reducing financial and operational risk and complexity while we continue to demonstrate responsible environmental stewardship. As a result of our focus on financial discipline, average per unit production expenses during the Current Quarter and Current Period decreased 5% and 7% from the Prior Quarter and the Prior Period, respectively, while per unit general and administrative expenses decreased 17% and 23% from the Prior Quarter and Prior Period, respectively.

Our substantial inventory of hydrocarbon resources provides a strong foundation for future growth. We believe that focusing on profitable and efficient growth from our captured resources will allow us to deliver attractive financial returns through all phases of the commodity price cycle. We have seen and continue to see increased efficiencies through our leveraging of first-well investments made in prior periods, including drilling on pre-existing pads. We also have a competitive capital allocation process designed to optimize our asset portfolio and identify the highest quality projects for future investment. To better understand our opportunities for continuous improvement, we benchmark our performance against that of our peers and evaluate the performance of completed projects. We also pay careful attention to safety, regulatory compliance and environmental stewardship measures while executing our business strategy.

Operating Results

Our Current Quarter production of 63 mmboe consisted of 271 bcf of natural gas (72% on an oil equivalent basis), 10 mmbbls of oil (16% on an oil equivalent basis) and 8 mmbbls of NGL (12% on an oil equivalent basis). Liquids represented 28% of total production for the Current Quarter, up from 25% in the Prior Quarter. Our daily production for the Current Quarter averaged approximately 695 mboe, an increase of 3% from the Prior Quarter and 13% when adjusted for 2013 asset sales. Compared to the Prior Quarter, our natural gas production in the Current Quarter decreased by 2%, or 69 mmcf per day; our oil production decreased by 2%, or approximately 2 mbbls per day; and our NGL production increased by 61%, or approximately 32 mbbls per day. Our natural gas, oil and NGL revenues (excluding gains or losses on natural gas and oil derivatives) increased approximately $48 million in the Current Quarter compared to the Prior Quarter, largely due to our NGL production increase and an increase in the price received for our oil production. See Results of Operations below for additional details.

Our Current Period production of 124 mmboe consisted of 531 bcf of natural gas (72% on an oil equivalent basis), 20 mmbbls of oil (16% on an oil equivalent basis) and 15 mmbbls of NGL (12% on an oil equivalent basis). Liquids represented 28% of total production for the Current Period, up from 24% in the Prior Period. Our daily production for the Current Period averaged approximately 685 mboe, an increase of 2% from the Prior Period and 12% when adjusted for 2013 asset sales. Compared to the Prior Period, our natural gas production in the Current Period decreased by 4%, or 107 mmcf per day; our oil production increased by 2%, or approximately 2 mbbls per day; and our NGL production increased by 58%, or approximately 31 mbbls per day. In addition, the price we received for our natural gas, oil and NGL production increased approximately 14%, from $28.57 per boe in the Prior Period to $32.79 per boe in the Current Period (excluding gains or losses on natural gas and oil derivatives). Our natural gas, oil and NGL revenues (excluding gains or losses on natural gas and oil derivatives) increased approximately $601 million in the Current Period compared to the Prior Period, largely due to our liquids production increase and an increase in the price received for our natural gas and oil production. See Results of Operations below for additional details.

Capital Expenditures

In the Current Quarter, our total capital expenditures were approximately $1.315 billion, of which drilling and completion costs were approximately $1.131 billion. This level of drilling and completion expenditures represents a decrease of approximately $472 million, or 29%, compared to the Prior Quarter. In the Current Quarter, we operated an average of 67 rigs, a decrease of nine rigs compared to the Prior Quarter. In addition to a decreased rig count, drilling and completion costs were lower in the Current Quarter than in the Prior Quarter as a result of improving capital efficiencies.

Net expenditures for the acquisition of unproved properties and geological and geophysical costs were approximately $54 million during the Current Quarter compared to approximately $63 million in the Prior Quarter. Other capital expenditures were approximately $130 million during the Current Quarter compared to approximately $145 million during the Prior Quarter. In addition, in the Current Quarter, we also purchased rigs and compressors previously sold under long-term lease arrangements for approximately $82 million to facilitate asset sales and the spin-off of our oilfield services business as discussed below under Strategic Transactions - Spin-Off of Oilfield Services Business.

In the Current Period, our total capital expenditures were approximately $2.152 billion, of which drilling and completion costs were approximately $1.860 billion. This level of drilling and completion expenditures represents a decrease of approximately $1.208 billion, or 39%, compared to the Prior Period. In the Current Period, we operated an average of 65 rigs, a decrease of 15 rigs compared to the Prior Period. In addition to a decreased rig count, drilling and completion costs were lower in the Current Period than in the Prior Period as a result of improving capital efficiencies.

Net expenditures for the acquisition of unproved properties and geological and geophysical costs were approximately $79 million during the Current Period compared to approximately $115 million in the Prior Period. Other capital expenditures were approximately $228 million during the Current Period compared to approximately $423 million during the Prior Period. The reduction in other capital expenditures is primarily the result of a reduction in capital expenditures for construction of our corporate headquarters and field offices and for our oilfield services business and the sale of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. In addition, in the Current Period, we also purchased rigs and compressors previously sold under long-term lease arrangements for approximately $422 million to facilitate asset sales and the spin-off of our oilfield services business as discussed below under Strategic Transactions - Spin-Off of Oilfield Services Business.

Based on planned activity levels for 2014, we project that total capital expenditures will be $5.0 - $5.4 billion, an approximate 24% decrease from $6.8 billion of total capital expenditures in 2013.

Strategic Transactions

We will continue to pursue opportunities to high-grade our portfolio so we can focus on assets that best align our strategy of profitable growth from captured resources. We seek strategic transactions that are value-accretive and enable us to further reduce financial complexity and lower overall leverage. Significant strategic transactions completed in the Current Period and subsequent to June 30, 2014 are described below.

Spin-Off of Oilfield Services Business

On June 30, 2014, we completed the spin-off of our oilfield services business, which we previously conducted through our indirect, wholly owned subsidiary Chesapeake Oilfield Operating, L.L.C. (COO), into an independent, publicly traded company called Seventy Seven Energy Inc. (SSE). On June 30, 2014, we distributed to Chesapeake shareholders one share of common stock of SSE and cash in lieu of fractional shares for every 14 shares of Chesapeake common stock outstanding on June 19, 2014, the record date for the distribution. Prior to the spin-off, SSE's services included drilling, hydraulic fracturing, oilfield rentals, rig relocation, and water transport and disposal. We believe the benefits of the spin-off include:

- enhancing the flexibility of the management team of Chesapeake and SSE to make strategic and operational decisions that are in the best interests of their respective businesses;
- optimizing the allocation of capital and corporate resources in a manner that focuses on achieving the strategic priorities of each company;
- enhancing SSE's ability to attract E&P customers other than Chesapeake;
- enhancing SSE's reputation as an independent provider of diversified oilfield services;
- enhancing the ability of each company to more efficiently attract and deploy capital; and
- enhancing the ability of Chesapeake and SSE to attract employees with appropriate skill sets, to incentivize their key employees with equity-based compensation that is aligned with the performance of their respective operations, and to retain key employees for the long term.

In connection with the spin-off, we entered into several agreements to define the terms and conditions of the spin-off and our ongoing relationship with SSE after the spin-off. These agreements, among other things, allocate responsibility for obligations arising before and after the distribution date, including obligations relating to taxes, employees and various transition services. Additionally, we entered into new services agreements with SSE that eliminated our previous utilization requirements and replaced them with rig-specific drilling contracts and created a three-year utilization requirement for hydraulic fracturing equipment. Because we expect to have continuing cash flows associated with SSE's operations through various agreements described above, our former oilfield services segment's historical financial results for periods up to the spin-off date will continue to be included in our historical financial results as a component of continuing operations. See Note 2 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the spin-off.

As a result the spin-off, we have experienced or anticipate the following effects:

- a reduction of approximately 5,100 employees;
- a reduction of $1.572 billion in aggregate principal amount of long-term debt as of June 30, 2014, consisting of $650 million of 6.625% Senior Notes due 2019, $500 million of 6.5% Senior Notes due 2022, a $400 million secured term loan and $22 million outstanding under SSE's new revolving credit facility; and
- the elimination of our oilfield services segment.

Sale of Investments

In January 2014, we received $209 million of net proceeds from the sale of our common equity ownership in Chaparral Energy, Inc. In March 2014, we sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million.

Sales of Buildings and Land

In the Current Period, we sold buildings and land noncore to our operations, primarily in the Oklahoma City area, for proceeds of approximately $106 million.

Midstream Compression Asset Sales

In March 2014, we sold 102 compressors and related equipment to Access Midstream Partners, L.P. for approximately $159 million. In April 2014, we sold 337 compressors and related equipment to Exterran Partners, L.P. for approximately $362 million.

Sale of Crude Oil Hauling Assets

In June 2014, we sold our crude oil hauling assets for approximately $44 million.

Oil and Gas Property Exchange with RKI

On July 29, 2014, we announced that we had entered into an agreement with RKI Exploration & Production, LLC (RKI) to exchange interests in approximately 440,000 gross acres in the Powder River Basin (PRB) in southeastern Wyoming. Under the agreement, Chesapeake will convey to RKI approximately 137,000 net acres and its interest in 67 gross wells, with an average working interest of approximately 22% in the northern portion of the PRB, where RKI is currently designated operator. In exchange, RKI will convey to Chesapeake approximately 203,000 net acres and its interest in 186 gross wells, with an average working interest of 48% in the southern portion of the PRB, where Chesapeake is currently designated operator. In addition to the exchange, we will pay RKI $450 million in cash. The transaction, which is subject to certain closing conditions, including the receipt of third-party consents, is expected to close in August 2014. Our interest in the properties acquired from RKI is subject to reduction if applicable participation rights are exercised and other conditions, including payment to us of consideration for such participation, are fulfilled.

Repurchase of CHK Utica Preferred Shares

On July 29, 2014, we repurchased all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders for approximately $1.26 billion, or approximately $1,189 per share including accrued dividends. The transaction eliminates approximately $75 million in annual cash dividend payments to third-party preferred shareholders. See Notes 7 and 20 of the notes to our condensed consolidated financial statements included in Item 1 of Part 1 of this report for further discussion of this repurchase.

Expected Second Half Divestitures

In the 2014 second half, Chesapeake expects to receive more than $700 million in proceeds from various assets sales that have closed, been previously announced or are underway. These transactions are expected to include noncore E&P assets in southwestern Pennsylvania, South Central Oklahoma, East Texas and South Texas, as well as additional compression assets and other miscellaneous real estate and equipment.

Liquidity and Capital Resources

Liquidity Overview

As of June 30, 2014, we had approximately $5.442 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our corporate revolving bank credit facility) compared to $4.909 billion as of December 31, 2013. As of June 30, 2014, we had full availability under our $4.0 billion corporate revolving bank credit facility. During the Current Period, we decreased our debt, net of unrestricted cash, by approximately $1.962 billion to $10.087 billion primarily as a result of the spin-off of our oilfield services business. As of June 30, 2014, we had negative working capital of approximately $1.422 billion compared to negative working capital of approximately $1.859 billion as of December 31, 2013. Working capital deficits exist primarily due to timing differences in the capital we spend and the revenues we receive from investing in natural gas and oil properties.

Through our oilfield services spin-off, divestitures and various other strategic transactions, we have taken steps to reduce financial leverage and complexity and further enhance our liquidity. While executing our strategic priorities, we have incurred certain cash outflows related to these transactions, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. As we continue to focus on our strategic priorities, certain actions that may reduce financial leverage and complexity could negatively impact our future results of operations and/or liquidity, and we may incur additional cash and noncash charges.

To add more certainty to our future estimated cash flows, we currently have downside price protection, in the form of over-the-counter derivative contracts, on approximately 69% of our remaining 2014 estimated natural gas production at an average price of $4.12 per mcf and 65% of our remaining 2014 estimated oil production at an average price of $94.25 per bbl. See Quantitative and Qualitative Disclosures about Market Risk in Item 3 of Part I in this report. Our use of derivative contracts allows us to reduce the effect of price volatility on our cash flows and EBITDA (defined as earnings before interest, taxes, depreciation, depletion and amortization), but the amount of estimated production subject to derivative contracts for any period depends on our outlook on future prices and risk assessment.

Based upon our 2014 capital expenditure budget, our forecasted operating cash flow and projected levels of indebtedness, we are projecting that we will continue to be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to various agreements described in Contractual Obligations and Off-Balance Sheet Arrangements below and in Note 5 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, recognizing that we may be required to meet such commitments even if our business plan assumptions were to change. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures and other spending to adapt to potential negative developments if needed.

Recent Refinancing

In the Current Quarter, we completed refinancing transactions designed to reduce our interest costs and to lengthen the maturity profile of our outstanding indebtedness. On April 24, 2014, we issued $3.0 billion in aggregate principal amount of senior notes at par. The offering included two series of notes: $1.5 billion in aggregate principal amount of Floating Rate Senior Notes due 2019 and $1.5 billion in aggregate principal amount of 4.875% Senior Notes due 2022. We used a portion of the net proceeds of $2.966 billion to repay the borrowings under, and terminate, our $2.0 billion term loan credit facility. We recorded a loss of $90 million, consisting of $40 million in premiums, $30 million of unamortized discount and $20 million of unamortized deferred charges, in connection with the termination. We used the remaining proceeds along with cash on hand to redeem the $97 million principal amount of 6.875% Senior Notes due 2018 and to purchase and redeem the $1.265 billion principal amount of the 9.5% Senior Notes due 2015 for $1.454 billion. We recorded a loss of approximately $6 million associated with the redemption of the 6.875% Senior Notes due 2018, which consisted $5 million in premiums and $1 million of unamortized deferred charges. We recorded a loss of approximately $99 million associated with the purchase and redemption of the 9.5% Senior Notes due 2015, which consisted of $87 million in premiums, $9 million of unamortized discount and $3 million of unamortized deferred charges.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Current Period and the Prior Period. See Notes 10, 11 and 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of sales of natural gas and oil assets, investments and other assets, respectively.

	Six Months Ended June 30,	
	2014	2013
	($ in millions)	
Cash provided by operating activities	$2,643	$2,205
Sales of natural gas and oil assets:		
Joint venture leasehold	8	39
Other natural gas and oil properties	240	1,856
Total sales of natural gas, oil and other assets	248	1,895
Sales of other assets:		
Sale of compressors to ACMP	159	—
Sale of compressors to Exterran	362	—
Sales of other property and equipment	192	459
Total proceeds from sales of other property and equipment	713	459
Other sources of cash and cash equivalents:		
Proceeds from sales of other investments	239	102
Proceeds from long-term debt, net	2,966	2,274
Proceeds from oilfield services long-term debt, net	888	
Other	—	201
Total other sources of cash and cash equivalents	4,093	2,577
Total sources of cash and cash equivalents	$7,697	$7,136

Cash provided by operating activities was $2.643 billion in the Current Period compared to $2.205 billion in the Prior Period. The increase in cash provided by operating activities is primarily the result of an increase in prices received for natural gas and oil sold (excluding the effect of gains or losses on derivatives), an increase in oil and NGL sales volumes and decreases in certain of our operating expenses per unit, partially offset by a decrease in natural gas production and NGL prices. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, impairments of other assets, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under Results of Operations.

Our $4.0 billion corporate revolving bank credit facility and cash and cash equivalents provide other sources of liquidity. We use our corporate revolving bank credit facility and cash on hand to fund daily operating activities and capital expenditures as needed. In the Current Period and the Prior Period, we also utilized a $500 million oilfield services credit facility. In connection with the spin-off of our oilfield services business, this facility was terminated in the Current Quarter. See Note 2 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the spin-off. We borrowed $857 million and repaid $1.239 billion in the Current Period and borrowed $6.559 billion and repaid $6.578 billion in the Prior Period under our revolving bank credit facilities. As of June 30, 2014, we had no borrowings outstanding under our corporate revolving bank credit facility and had utilized approximately $20 million of the facility for various letters of credit. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves is currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations that our lenders might make in the future. We believe our borrowing capacity under our corporate facility will not be reduced as a result of any such future redeterminations.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the Current Period and the Prior Period:

	Six Months Ended June 30,	
	2014	2013
	($ in millions)	
Natural Gas and Oil Expenditures:		
Drilling and completion costs[a]	$(1,976)	$(3,117)
Acquisitions of proved and unproved properties	(59)	(170)
Geological and geophysical costs	(20)	(28)
Interest capitalized on unproved properties	(297)	(380)
Total natural gas and oil expenditures	(2,352)	(3,695)
Other Uses of Cash and Cash Equivalents:		
Cash paid to repurchase debt	(3,362)	(1,874)
Additions to other property and equipment	(153)	(464)
Payments on credit facility borrowings, net	(382)	(19)
Cash paid to purchase leased rigs and compressors	(422)	(3)
Cash paid for oilfield service equipment deposits	(45)	(39)
Cash paid for prepayment of mortgage	—	(55)
Cash paid to purchase preferred shares of subsidiary	—	(212)
Dividends paid	(203)	(202)
Distributions to noncontrolling interest owners	(105)	(111)
Cash paid for financing derivatives[b]	(32)	(25)
Additions to investments	(5)	(4)
Other	(11)	(43)
Total other uses of cash and cash equivalents	(4,720)	(3,051)
Total uses of cash and cash equivalents	$(7,072)	$(6,746)

(a) Net of $357 million and $436 million in drilling and completion carries received from our joint venture partners during the Current Period and the Prior Period, respectively.

(b) Reflects derivatives deemed to contain, for accounting purposes, a significant financing element at contract inception.

Our primary use of funds is for capital expenditures for drilling and completion costs on our natural gas and oil properties. Historically, a significant use was also for the acquisition of leasehold and construction and acquisition of other property and equipment. During the Current Period, our average operated rig count was 65 rigs compared to an average rig count of 80 operated rigs in the Prior Period.

Capital expenditures related to our midstream, oilfield services and other fixed assets were $153 million and $464 million during the Current Period and the Prior Period, respectively. The reduction of such expenditures in the Current Period from the Prior Period is primarily the result of reduced capital expenditures for construction of our corporate headquarters, field offices and our oilfield services business and the sale of substantially all of our midstream business and most of our gathering assets in 2012 and 2013.

In the Current Period, we also purchased rigs and compressors previously sold under long-term lease arrangements for approximately $422 million as part of a strategic initiative to reduce complexity and future commitments as well as to facilitate asset sales and the spin-off of SSE. In addition, we made deposits of $45 million on oilfield services equipment that was included in the spin-off described above.

We paid dividends on our common stock of $117 million in the Current Period and $116 million in the Prior Period. We paid dividends on our preferred stock of $86 million in both the Current Period and the Prior Period.

Bank Credit Facilities

During the Current Period, we had the following two revolving bank credit facilities as sources of liquidity:

	Corporate Credit Facility[a]	Oilfield Services Credit Facility[b]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of June 30, 2014	$—	$—
Letters of credit outstanding as of June 30, 2014	$20	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower was Chesapeake Oilfield Operating, L.L.C. (COO). The facility was terminated in the Current Quarter in connection with the spin-off of our oilfield services business. See Note 2 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the spin-off.

Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by proved reserves and bear interest at a variable rate. Although the applicable interest rates under our corporate credit facility fluctuate based on our long-term senior unsecured credit ratings, our credit facility does not contain provisions which would trigger an acceleration of amounts due under the facility or a requirement to post additional collateral in the event of a downgrade of our credit ratings. We were in compliance with all covenants under the credit facility agreement as of June 30, 2014, including the financial covenant requiring us to maintain an indebtedness to EBITDA ratio of 4.0 to 1.0. As of June 30, 2014, our indebtedness to EBITDA ratio was approximately 2.34 to 1.00. The ratio compares consolidated indebtedness to consolidated EBITDA, both non-GAAP financial measures that are defined in the credit facility agreement, for the 12-month period ending on the measurement date. Consolidated indebtedness consists of outstanding indebtedness, less the cash and cash equivalents of Chesapeake and certain of our subsidiaries. Consolidated EBITDA consists of the net income of Chesapeake and certain of our subsidiaries, excluding income from investments and non-cash income, plus interest expense, taxes, depreciation, amortization expense and other non-cash or non-recurring expenses, and is calculated on a pro forma basis to give effect to any acquisitions, divestitures or other adjustments. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the terms of our corporate credit facility.

Hedging Facility

We have a multi-counterparty secured hedging facility with 18 counterparties that have committed to provide approximately 1.063 bboe of hedging capacity for natural gas, oil and NGL price derivatives and 1.063 bboe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. For further discussion of the terms of our hedging facility, see Note 9 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Term Loan

Prior to April 24, 2014, we had a $2.0 billion unsecured term loan credit facility. We used a portion of the proceeds from our offering of $3.0 billion in aggregate principal amount of senior notes that closed on April 24, 2014 to repay the borrowings under and terminate the term loan. See Recent Refinancing above for further discussion of the refinancing transactions. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the term loan.

Senior Note Obligations

Our senior note obligations consisted of the following as of June 30, 2014:

	June 30, 2014 ($ in millions)
3.25% senior notes due 2016	$500
6.25% euro-denominated senior notes due 2017[(a)]	471
6.5% senior notes due 2017	660
7.25% senior notes due 2018	669
Floating rate senior notes due 2019	1,500
6.625% senior notes due 2020	1,300
6.875% senior notes due 2020	500
6.125% senior notes due 2021	1,000
5.375% senior notes due 2021	700
4.875% senior notes due 2022	1,500
5.75% senior notes due 2023	1,100
2.75% contingent convertible senior notes due 2035[(b)]	396
2.5% contingent convertible senior notes due 2037[(b)]	1,168
2.25% contingent convertible senior notes due 2038[(b)]	347
Discount on senior notes[(c)]	(272)
Interest rate derivatives[(d)]	10
Total senior notes, net	$11,549

(a) The principal amount shown is based on the exchange rate of $1.3692 to €1.00 as of June 30, 2014. See Note 9 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our related foreign currency derivatives.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process.

(c) Included in this discount was $264 million as of June 30, 2014 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(d) See Note 9 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for discussion related to these instruments.

For further discussion and details regarding our senior notes, contingent convertible senior notes and COO senior notes, see Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas, oil and NGL prices, interest rate and foreign currency volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of June 30, 2014, our natural gas, oil and interest rate derivative instruments were spread among 17 counterparties. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their obligations in excess of defined thresholds. We use this facility for substantially all of our natural gas, oil and NGL derivatives.

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL ($1.638 billion as of June 30, 2014) and exploration and production companies that own interests in properties we operate ($551 million as of June 30, 2014). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic,

industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Period and the Prior Period, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. As of June 30, 2014, these arrangements and transactions included (i) operating lease agreements, (ii) VPPs (to purchase production and pay related production expenses and taxes in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit, (vii) open gathering and transportation commitments and (viii) various other commitments we enter into in the ordinary course of business that could result in a future cash obligation. See Notes 5 and 10 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of commitments and VPPs, respectively.

Results of Operations – Three Months Ended June 30, 2014 vs. June 30, 2013

General. For the Current Quarter, Chesapeake had net income of $230 million, or $0.22 per diluted common share, on total revenues of $5.152 billion. This compares to net income of $625 million, or $0.66 per diluted common share, on total revenues of $4.675 billion during the Prior Quarter. The decrease in net income in the Current Quarter was primarily driven by a decrease in unrealized gains on our natural gas and oil derivative contracts.

Natural Gas, Oil and NGL Sales. During the Current Quarter, natural gas, oil and NGL sales were $1.704 billion compared to $2.406 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 63 mmboe for $1.917 billion at a weighted average price of $30.32 per boe, compared to 62 mmboe produced and sold in the Prior Quarter for $1.869 billion at a weighted average price of $30.36 per boe (excluding the effect of derivatives). The decrease in the price received per boe in the Current Quarter compared to the Prior Quarter resulted in a decrease in revenues of $3 million and increased sales volumes resulted in a $50 million increase in revenues, for a total increase in revenues of $47 million (excluding the effect of derivatives).

For the Current Quarter, our average price received per mcf of natural gas was $2.76 compared to $2.81 in the Prior Quarter (excluding the effect of derivatives). Oil prices received per barrel (excluding the effect of derivatives) were $97.49 and $92.53 in the Current Quarter and the Prior Quarter, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $21.03 and $24.22 in the Current Quarter and the Prior Quarter, respectively.

Natural gas prices after gathering, transportation and basis differentials were $1.91 per mcf below the Henry Hub natural gas benchmark price in the Current Quarter compared to $1.29 per mcf in the Prior Quarter. This was primarily the result of significant weakening of Marcellus shale basis differentials in addition to increased gathering and transportation costs.

Gains and losses from our natural gas, oil and NGL derivatives resulted in a net decrease in natural gas, oil and NGL revenues of $213 million in the Current Quarter and a net increase of $537 million in the Prior Quarter. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of June 30, 2014.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming our Current Quarter production levels and without considering the effect of derivatives, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in the Current Quarter revenues and cash flows of approximately $27 million and $26 million, respectively, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in the Current Quarter revenues and cash flows of approximately $18 million and $17 million, respectively.

The following tables show our production and average sales prices received by operating division for the Current Quarter and the Prior Quarter:

	Three Months Ended June 30, 2014								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	144.2	2.80	8.7	98.84	3.9	26.26	36.6	58	37.23
Northern[c]	127.1	2.73	1.6	90.33	3.8	15.61	26.6	42	20.82
Total[d]	271.3	2.76	10.3	97.49	7.7	21.03	63.2	100 %	30.32

	Three Months Ended June 30, 2013								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	182.4	2.55	9.9	92.88	4.0	23.10	44.2	72	33.37
Northern[c]	95.2	3.29	0.6	87.04	0.8	29.65	17.3	28	22.70
Total[d]	277.6	2.81	10.5	92.53	4.8	24.22	61.5	100 %	30.36

(a) The average sales price excludes gains (losses) on derivatives.

(b) Our Southern Division includes the Eagle Ford, Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime unconventional liquids plays and the Haynesville/Bossier and Barnett unconventional natural gas shale plays. The Eagle Ford Shale accounted for approximately 19% of our estimated proved reserves by volume as of December 31, 2013. Production for the Eagle Ford Shale for the Current Quarter and the Prior Quarter was 8.3 mmboe and 8.1 mmboe, respectively. The Barnett Shale accounted for approximately 16% of our estimated proved reserves by volume as of December 31, 2013. Production for the Barnett Shale for the Current Quarter and the Prior Quarter was 6.2 mmboe and 7.0 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play. The Marcellus Shale accounted for approximately 25% of our estimated proved reserves by volume as of December 31, 2013. Production for the Marcellus Shale for the Current Quarter and the Prior Quarter was 18.7 mmboe and 15.1 mmboe, respectively.

(d) Current Quarter and Prior Quarter production levels reflect the impact of various asset sales and joint ventures. The decrease in production in the Southern Division from the Prior Quarter to the Current Quarter is primarily the result of our Mississippi Lime joint venture in the Prior Quarter and asset sale in the Haynesville Shale in the third quarter of 2013. The increase in production in the Northern Division from the Prior Quarter to the Current Quarter is primarily the result of increased processing capacity in the Utica Shale. See Note 10 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our natural gas and oil property divestitures and joint ventures.

Our average daily production of 695 mboe for the Current Quarter consisted of approximately 3.0 bcf of natural gas (72% on an oil equivalent basis) and approximately 197,700 bbls of liquids, consisting of approximately 113,400 bbls of oil (16% on an oil equivalent basis) and approximately 84,300 bbls of NGL (12% on an oil equivalent basis). Our year-over-year growth rate of NGL production was 61%. Oil and natural gas production each declined 2% year over year primarily as a result of asset sales.

Excluding the impact of derivatives, our percentage of revenues from natural gas, oil and NGL is shown in the following table:

	Three Months Ended June 30,	
	2014	2013
Natural gas	39%	42%
Oil	53%	52%
NGL	8%	6%
Total	100%	100%

74

We are defending against claims by royalty owners alleging that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. Adverse results in these matters would cause our obligations to royalty owners to increase, which would result in a decrease in our future revenues.

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues and expenses consist of third-party revenues and expenses related to our marketing, gathering and compression operations and exclude depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. Chesapeake recognized $3.167 billion in marketing, gathering and compression revenues in the Current Quarter with corresponding expenses of $3.166 billion, for a net margin before depreciation of $1 million. This compares to revenues of $2.057 billion, expenses of $2.028 billion and a net margin before depreciation of $29 million in the Prior Quarter. The margin decrease from the Prior Quarter to the Current Quarter was primarily a result of the sale of a significant portion of our compression assets in the Current Quarter, the sale of gathering assets in 2013 and lower margin on sales contracts with third parties to help meet certain of our pipeline commitments. Revenues and operating expenses from our marketing business increased substantially in the Current Quarter compared to the Prior Quarter as we marketed significantly more oil and NGL for third parties. Our marketing revenues and operating expenses also increased because of a variety of purchase and sales contracts we entered into with third parties for various commercial purposes, including credit risk mitigation and to help meet certain of our pipeline delivery commitments.

Oilfield Services Revenues and Expenses. Oilfield services consists of third-party revenues and expenses related to our former oilfield services operations and excludes depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our oilfield services assets. Chesapeake recognized $281 million in oilfield services revenues in the Current Quarter with corresponding expenses of $212 million, for a net margin before depreciation of $69 million. This compares to revenues of $212 million, expenses of $177 million and a net margin before depreciation of $35 million in the Prior Quarter. Oilfield services revenues, expenses and margin increased in the Current Quarter compared to the Prior Quarter primarily as a result of increased third-party utilization for all of our oilfield services. As a result of the spin-off of our oilfield services business, we will no longer have oilfield services revenues and expenses in future periods.

Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $282 million in the Current Quarter, compared to $288 million in the Prior Quarter. On a unit-of-production basis, production expenses were $4.46 per boe in the Current Quarter compared to $4.68 per boe in the Prior Quarter. The per unit expense decrease in the Current Quarter was primarily the result of a general improvement in operating efficiencies across most of our operating areas. Production expenses in the Current Quarter and the Prior Quarter included approximately $38 million and $40 million, or $0.59 and $0.65 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease and as operating efficiencies generally improve.

Production Taxes. Production taxes were $72 million in the Current Quarter compared to $59 million in the Prior Quarter. On a unit-of-production basis, production taxes were $1.14 per boe in the Current Quarter compared to $0.95 per boe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas, oil and NGL prices are higher. The $13 million increase in production taxes in the Current Quarter was primarily due to an increase in production from the Prior Quarter to the Current Quarter. Production taxes in the Current Quarter and the Prior Quarter included approximately $6 million and $5 million, or $0.09 and $0.08 per boe, respectively, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses were $90 million in the Current Quarter and $106 million in the Prior Quarter, or $1.43 and $1.73 per boe, respectively. The absolute and per unit expense decrease in the Current Quarter was primarily due to our efforts to reduce costs and increased emphasis on operational efficiencies. Our workforce reduction in the second half of 2013 has resulted in cost savings and the spin-off of our oilfield services business, which included the separation of 5,100 employees, will reduce our general and administrative expenses by an additional nominal amount in the future. The majority of the payroll and benefits associated with oilfield services employees was included as oilfield services, and not general and administrative, expenses in our statements of operations. Included in general and administrative expenses is stock-based compensation of $11 million in the Current Quarter and $15 million in the Prior Quarter. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our stock-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $55 million and $80 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition and drilling and completion efforts. The decrease was primarily due to a decrease in our drilling activity, lower costs and increased emphasis on operational efficiencies in support of our current business strategy.

Restructuring and Other Termination Costs. We recorded $33 million and $7 million of restructuring and other termination costs in the Current Quarter and the Prior Quarter, respectively. The Current Quarter amount primarily related to charges incurred in connection with the spin-off of our oilfield services business and senior management separations. The Prior Quarter amount primarily related to our voluntary separation plan and senior management separations. See Note 15 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our restructuring and other termination costs.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $661 million and $645 million in the Current Quarter and the Prior Quarter, respectively. The $16 million increase in the Current Quarter is primarily driven by an increase in our production. The average DD&A rate per boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $10.45 and $10.48 in the Current Quarter and the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $79 million in the Current Quarter and $76 million the Prior Quarter. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. To the extent company-owned oilfield services equipment was used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) was capitalized in natural gas and oil properties as drilling and completion costs. In the Current Quarter, we completed the spin-off of our oilfield services business and, therefore, will not incur oilfield services depreciation expense in future periods. The following table shows depreciation expense by asset class for the Current Quarter and the Prior Quarter, and the estimated useful lives of these assets.

	Three Months Ended June 30,		Estimated
	2014	2013	Useful Life
	($ in millions)		(in years)
Oilfield services equipment[(a)]	$37	$27	3 - 15
Buildings and improvements	12	11	10 - 39
Natural gas compressors[(b)]	9	9	3 - 20
Computers and office equipment	8	11	3 - 7
Vehicles	7	9	0 - 7
Natural gas gathering systems and treating plants[(b)]	3	3	20
Other	3	6	2 - 20
Total depreciation and amortization of other assets	$79	$76	

(a) Included in our former oilfield services operating segment.
(b) Included in our marketing, gathering and compression operating segment.

Impairments of Fixed Assets and Other. In the Current Quarter and the Prior Quarter, we recognized $40 million and $231 million, respectively, of fixed asset impairment losses and other charges. The Current Quarter amount is primarily related to charges recorded for a joint venture net acreage shortfall and impairments related to a gathering system. The Prior Quarter impairments primarily related to buildings and land. See Note 14 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our impairments of fixed assets and other.

Net Gains on Sales of Fixed Assets. In the Current Quarter, net gains on sales of fixed assets were $93 million compared to $109 million in the Prior Quarter. The Current Quarter amount primarily related to the sale of natural gas compressors. The Prior Quarter amount primarily related to the sale of certain of our midstream gathering systems. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our net gains on sales of fixed assets.

Interest Expense. Interest expense was $27 million in the Current Quarter compared to $104 million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2014	2013
	($ in millions)	
Interest expense on senior notes	$184	$194
Interest expense on term loans	7	29
Amortization of loan discount, issuance costs and other	16	30
Interest expense on credit facilities	9	11
Realized (gains) losses on interest rate derivatives[a]	(3)	(1)
Unrealized (gains) losses on interest rate derivatives[b]	(31)	51
Capitalized interest	(155)	(210)
Total interest expense	$27	$104
Average senior notes borrowings	$12,196	$11,657
Average term loan borrowings	$527	$2,000
Average credit facilities borrowings	$434	$907

(a) Includes settlements related to the Current Quarter interest accrual and the effect of gains (losses) on early-terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(b) Includes changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.92 per boe in the Current Quarter compared to $0.85 per boe in the Prior Quarter. The increase in Current Quarter interest expense per boe was primarily due to a decrease in the amount of interest capitalized as a result of a lower average balance of unevaluated natural gas and oil properties, the primary asset on which interest is capitalized. The decrease in total interest expense from the Prior Quarter to the Current Quarter is due to a decrease in unrealized losses on our interest rate derivatives.

Earnings (Losses) on Investments. Losses on investments were $24 million in the Current Quarter compared to earnings of $23 million in the Prior Quarter. The Current Quarter losses primarily related to our equity in the net loss of FTS International, Inc. (FTS). The Prior Quarter earnings were primarily related to our equity in the net income of FTS.

Net Loss on Sales of Investments. In the Prior Quarter, we recorded a loss on sales of investments of $10 million. We recorded a $15 million loss related to the sale of our Clean Energy convertible note investment. In addition, in the Prior Quarter we sold an equity investment for cash proceeds of $6 million and recorded a $5 million gain.

Losses on Purchases of Debt. In the Current Quarter, we repaid the borrowings under and terminated our $2.0 billion term loan credit facility due 2017 and recorded a loss of approximately $90 million, including $40 million in premiums, $30 million of unamortized discount and $20 million of unamortized deferred charges. Also in the Current Quarter, we purchased and redeemed $1.265 billion in aggregate principal amount of our 9.5% Senior Notes due 2015 for $1.352 billion. We recorded a loss of approximately $99 million associated with the purchase and redemption, including $87 million in premiums, $9 million of unamortized debt discount and $3 million of unamortized deferred charges. In addition, in the Current Quarter, we redeemed $97 million in principal amount of our 6.875% Senior Notes

due 2018 at par. We recorded a loss of approximately $6 million associated with the redemption, including $5 million in premiums and $1 million of unamortized deferred charges.

In the Prior Quarter, we completed tender offers to purchase $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million. We recorded a loss of approximately $37 million associated with these tender offers, including $32 million in premiums and $5 million of unamortized deferred changes. In addition, in the Prior Quarter, we redeemed $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 at par. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of debt discount.

Other Income. Other income was $7 million in the Current Quarter and $3 million in the Prior Quarter. Both the Current Quarter and the Prior Quarter other income consisted primarily of miscellaneous income.

Income Tax Expense. Chesapeake recorded income tax expense of $141 million and $384 million in the Current Quarter and the Prior Quarter, respectively. Our effective income tax rate was 38.1% in the Current Quarter and 38.0% in the Prior Quarter. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $39 million and $45 million in the Current Quarter and the Prior Quarter, respectively. Net income attributable to noncontrolling interests is primarily driven by the dividends paid on preferred stock of our subsidiaries CHK Utica, L.L.C. (CHK Utica) and CHK Cleveland Tonkawa L.L.C. (CHK C-T), in addition to income or loss related to the Chesapeake Granite Wash Trust. See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of these entities.

Results of Operations – Six Months Ended June 30, 2014 vs. June 30, 2013

General. For the Current Period, Chesapeake had net income of $696 million, or $0.78 per diluted common share, on total revenues of $10.198 billion. This compares to net income of $728 million, or $0.72 per diluted common share, on total revenues of $8.098 billion during the Prior Period. The decrease in net income in the Current Period was primarily driven by a decrease in unrealized gains and an increase in unrealized losses on our natural gas and oil derivative contracts, partially offset by increased production, higher prices we received for our natural gas, oil and NGL sold and decreases in certain of our operating expenses.

Natural Gas, Oil and NGL Sales. During the Current Period, natural gas, oil and NGL sales were $3.471 billion compared to $3.858 billion in the Prior Period. In the Current Period, Chesapeake produced and sold 124 mmboe for $4.065 billion at a weighted average price of $32.79 per boe, compared to 121 mmboe produced and sold in the Prior Period for $3.464 billion at a weighted average price of $28.57 per boe (excluding the effect of derivatives). The increase in the price received per boe in the Current Period compared to the Prior Period resulted in an increase in revenues of $523 million, and increased sales volumes resulted in a $78 million increase in revenues, for a total increase in revenues of $601 million (excluding the effect of derivatives).

For the Current Period, our average price received per mcf of natural gas was $3.30 compared to $2.45 in the Prior Period (excluding the effect of derivatives). Oil prices received per barrel (excluding the effect of derivatives) were $95.59 and $93.79 in the Current Period and the Prior Period, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $25.10 and $26.26 in the Current Period and the Prior Period, respectively.

Natural gas prices after gathering, transportation and basis differentials were $1.50 per mcf below the Henry Hub natural gas benchmark price in the Current Period compared to $1.27 per mcf in the Prior Period. This was primarily the result of significant weakening of Marcellus shale basis differentials in addition to increased gathering and transportation costs.

Gains and losses from our natural gas, oil and NGL derivatives resulted in a net decrease in natural gas, oil and NGL revenues of $594 million in the Current Period and a net increase of $394 million in the Prior Period. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of June 30, 2014.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming our Current Period production levels and without considering the effect of derivatives, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in the Current Period revenues and cash flows of approximately $53 million and $52 million, respectively, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in the Current Period revenues and cash flows of approximately $35 million and $34 million, respectively.

The following tables show our production and average sales prices received by operating division for the Current Period and the Prior Period:

	Six Months Ended June 30, 2014								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	284.0	2.98	17.1	96.83	8.2	28.10	72.6	58	37.65
Northern[c]	247.4	3.67	3.0	88.64	7.0	21.64	51.4	42	25.91
Total[d]	531.4	3.30	20.1	95.59	15.2	25.10	124.0	100 %	32.79

	Six Months Ended June 30, 2013								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	375.0	2.24	18.7	94.20	8.1	24.73	89.3	74	31.40
Northern[c]	175.8	2.92	1.1	86.63	1.5	34.35	31.9	26	20.64
Total[d]	550.8	2.45	19.8	93.79	9.6	26.26	121.2	100 %	28.57

(a) The average sales price excludes gains (losses) on derivatives.

(b) Our Southern Division includes the Eagle Ford, Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime unconventional liquids plays and the Haynesville/Bossier and Barnett unconventional natural gas shale plays. The Eagle Ford Shale accounted for approximately 19% of our estimated proved reserves by volume as of December 31, 2013. Production for the Eagle Ford Shale for the Current Period and the Prior Period was 16.2 mmboe and 14.9 mmboe, respectively. The Barnett Shale accounted for approximately 16% of our estimated proved reserves by volume as of December 31, 2013. Production for the Barnett Shale for the Current Period and the Prior Period was 12.7 mmboe and 14.2 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play. The Marcellus Shale accounted for approximately 25% of our estimated proved reserves by volume as of December 31, 2013. Production for the Marcellus Shale for the Current Period and the Prior Period was 37.5 mmboe and 27.9 mmboe, respectively.

(d) Current Period and Prior Period production levels reflect the impact of various asset sales and joint ventures. The decrease in production in the Southern Division from the Prior Period to the Current Period is primarily the result of our Mississippi Lime joint venture in the Prior Quarter and asset sale in the Haynesville Shale in the third quarter of 2013. The increase in production in the Northern Division from the Prior Period to the Current Period is primarily the result of increased processing capacity in the Utica Shale. See Note 10 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our natural gas and oil property divestitures and joint ventures.

Our average daily production of 685 mboe for the Current Period consisted of approximately 2.9 bcf of natural gas (72% on an oil equivalent basis) and approximately 195,700 bbls of liquids, consisting of approximately 111,500 bbls of oil (16% on an oil equivalent basis) and approximately 84,200 bbls of NGL (12% on an oil equivalent basis). Our year-over-year growth rate of oil production was 2% and our year-over-year growth rate of NGL production was 58%. Natural gas production declined 4% year over year primarily as a result of asset sales.

Excluding the impact of derivatives, our percentage of revenues from natural gas, oil and NGL is shown in the following table:

	Six Months Ended June 30,	
	2014	2013
Natural gas	43%	39%
Oil	48%	54%
NGL	9%	7%
Total	100%	100%

We are defending against claims by royalty owners alleging that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. Adverse results in these matters would cause our obligations to royalty owners to increase, which would result in a decrease in our future revenues.

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues and expenses consist of third-party revenues and expenses related to our marketing, gathering and compression operations and exclude depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. Chesapeake recognized $6.182 billion in marketing, gathering and compression revenues in the Current Period with corresponding expenses of $6.147 billion, for a net margin before depreciation of $35 million. This compares to revenues of $3.838 billion, expenses of $3.772 billion and a net margin before depreciation of $66 million in the Prior Period. The margin decrease from the Prior Period to the Current Period was primarily a result of the sale of a significant portion of our compression assets in the Current Period, the sale of gathering assets in 2013 and lower margin on sales contracts with third parties to meet certain of our pipeline commitments. Revenues and operating expenses from our marketing business increased substantially in the Current Period compared to the Prior Period as we marketed significantly more oil and NGL from Chesapeake-operated wells and for third parties. Our marketing revenues and operating expenses also increased because of a variety of purchase and sales contracts we entered into with third parties for various commercial purposes, including credit risk mitigation and to help meet certain of our pipeline delivery commitments.

Oilfield Services Revenues and Expenses. Oilfield services consists of third-party revenues and expenses related to our former oilfield services operations and excludes depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our oilfield services assets. Chesapeake recognized $545 million in oilfield services revenues in the Current Period with corresponding expenses of $431 million, for a net margin before depreciation of $114 million. This compares to revenues of $402 million, expenses of $332 million and a net margin before depreciation of $70 million in the Prior Period. Oilfield services revenues, expenses and margin increased in the Current Period compared to the Prior Period primarily as a result of increased third-party utilization for all of our oilfield services. As a result of the spin-off of our oilfield services business, we will no longer have oilfield services revenues and expenses in future periods.

Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $570 million in the Current Period, compared to $595 million in the Prior Period. On a unit-of-production basis, production expenses were $4.59 per boe in the Current Period compared to $4.91 per boe in the Prior Period. The per unit expense decrease in the Current Period was primarily the result of a general improvement in operating efficiencies across most of our operating areas. Production expenses in the Current Period and the Prior Period included approximately $80 million and $85 million, or $0.65 and $0.70 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease and operating efficiencies generally improve.

Production Taxes. Production taxes were $122 million in the Current Period compared to $112 million in the Prior Period. On a unit-of-production basis, production taxes were $0.99 per boe in the Current Period compared to $0.92 per boe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas, oil and NGL prices are higher. The $10 million increase from the Prior Period to the Current Period was primarily due to the increase in the unhedged price for our natural gas and oil production from $28.57 per boe to $32.79 per boe, in addition to increased production. Production taxes in the Current Period and the Prior Period included approximately $10 million and $12 million, or $0.08 and $0.10 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production tax expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease.

General and Administrative Expenses. General and administrative expenses were $169 million in the Current Period and $216 million in the Prior Period, or $1.37 and $1.78 per boe, respectively. The absolute and per unit expense decrease in the Current Period was primarily due to our efforts to reduce costs and increased emphasis on operational efficiencies. Our workforce reduction in the second half of 2013 has resulted in cost savings, and the spin-off of our oilfield services business, which included the separation of 5,100 employees, will reduce our general and administrative expenses by an additional nominal amount in the future. The majority of the payroll and benefits associated with oilfield services employees was included as oilfield services, and not general and administrative, expenses in our statements of operations. Included in general and administrative expenses is stock-based compensation of $24 million in the Current Period and $35 million in the Prior Period. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our stock-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with acquisition of leasehold and drilling and completion activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $112 million and $172 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our natural gas and oil property acquisition and drilling and completion efforts. The decrease was primarily due to a decrease in our drilling activity, lower costs and increased emphasis on operational efficiencies in support of our current business strategy.

Restructuring and Other Termination Costs. We recorded $26 million and $140 million of restructuring and other termination costs in the Current Period and the Prior Period, respectively. The Current Period amount primarily related to charges incurred in connection with the spin-off of our oilfield services business and senior management separations. The Prior Period amount primarily related to our voluntary separation plan and senior management separations. See Note 15 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our restructuring and other termination costs.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $1.288 billion and $1.293 billion in the Current Period and the Prior Period, respectively. The $5 million decrease in the Current Period is primarily driven by efficiencies in our drilling program as a result of lower development costs and higher estimated reserve recoveries in addition to upward price revisions to our estimated proved reserves, partially offset by an increase in production. The average DD&A rate per boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $10.39 and $10.67 in the Current Period and the Prior Period, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $157 million in the Current Period and $154 million in the Prior Period. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. To the extent company-owned oilfield services equipment was used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) was capitalized in natural gas and oil properties as drilling and completion costs. In the Current Period, we completed the spin-off of our oilfield services business and, therefore, will not incur oilfield services depreciation expense in future periods. The following table shows depreciation expense by asset class for the Current Period and the Prior Period, and the estimated useful lives of these assets.

	Six Months Ended June 30,		Estimated
	2014	2013	Useful Life
	($ in millions)		(in years)
Oilfield services equipment[(a)]	$74	$53	3 - 15
Buildings and improvements	22	25	10 - 39
Natural gas compressors[(b)]	17	18	3 - 20
Computers and office equipment	17	23	3 - 7
Vehicles	14	20	0 - 7
Natural gas gathering systems and treating plants[(b)]	6	6	20
Other	7	9	2 - 20
Total depreciation and amortization of other assets	$157	$154	

(a) Included in our former oilfield services operating segment.
(b) Included in our marketing, gathering and compression operating segment.

Impairments of Fixed Assets and Other. In the Current Period and the Prior Period, we recognized $60 million and $258 million, respectively, of fixed asset impairment losses and other charges. The Current Period losses primarily related to charges recorded for a joint venture net acreage shortfall, impairments related to a gathering system and impairments related to certain of our drilling rigs. The Prior Period charges primarily related to buildings and land. See Note 14 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our impairments of fixed assets and other.

Net Gains on Sales of Fixed Assets. In the Current Period, net gains on sales of fixed assets were $115 million compared to $158 million in the Prior Period. The Current Period amount primarily related to gains on sales of natural gas compressors and our crude oil hauling assets, partially offset by losses on sales of drilling rigs and certain of our gathering assets. The Prior Period amount primarily consisted of gains on sales of gathering assets partially offset by losses on the sales of buildings and land. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our net gains on sales of fixed assets.

Interest Expense. Interest expense was $66 million in the Current Period compared to $124 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2014	2013
	($ in millions)	
Interest expense on senior notes	$364	$380
Interest expense on term loans	36	58
Amortization of loan discount, issuance costs and other	35	48
Interest expense on credit facilities	17	22
Realized (gains) losses on interest rate derivatives[(a)]	(6)	(3)
Unrealized (gains) losses on interest rate derivatives[(b)]	(47)	57
Capitalized interest	(333)	(438)
Total interest expense	$66	$124
Average senior notes borrowings	$11,506	$11,156
Average term loan borrowings	$1,260	$2,000
Average credit facilities borrowings	$437	$998

(a) Includes settlements related to the Current Period interest accrual and the effect of gains (losses) on early-terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(b) Includes changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.91 per boe in the Current Period compared to $0.55 per boe in the Prior Period. The increase in Current Period interest expense per boe was primarily due to a decrease in the amount of interest capitalized as a result of a lower average balance of unevaluated natural gas and oil properties, the primary asset on which interest is capitalized. The decrease in total interest expense was due to a decrease in unrealized losses on interest rate derivatives.

Losses on Investments. Losses on investments were $45 million in the Current Period compared to losses of $14 million in the Prior Period. The Current Period losses primarily related to our equity in the net loss of FTS. The Prior Period losses related to our equity in the net loss of our Sundrop Fuels investment, offset by earnings from our FTS investment.

Net Gains (Losses) on Sales of Investments. We recorded net gains on sales of investments of $67 million in the Current Period and net losses on sales of investments of $10 million in the Prior Period. In the Current Period, we sold all of our interest in Chaparral Energy, Inc. for cash proceeds of $215 million and recorded a $73 million gain related to the sale. We also sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction. In the Prior Period, we recorded a $15 million loss related to the sale of our Clean Energy convertible note investment. In addition, in the Prior Period we sold an investment for cash proceeds of $6 million and recorded a $5 million gain.

Losses on Purchases of Debt. In the Current Period, we repaid the borrowings under and terminated our $2.0 billion term loan credit facility due 2017 and recorded a loss of approximately $90 million, including $40 million in premiums, $30 million of unamortized discount and $20 million of unamortized deferred charges. Also in the Current Period, we purchased and redeemed $1.265 billion in aggregate principal amount of our 9.5% Senior Notes due 2015 for $1.352 billion. We recorded a loss of approximately $99 million associated with the purchase and redemption, including $87 million in premiums, $9 million of unamortized debt discount and $3 million of unamortized deferred charges. In addition, in the Current Period, we redeemed $97 million in principal amount of our 6.875% Senior Notes due 2018 at par. We recorded a loss of approximately $6 million associated with the redemption, including $5 million in premiums and $1 million of unamortized deferred charges.

In the Prior Period, we completed tender offers to purchase $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million. We recorded a loss of approximately $37 million associated with these tender offers, including $32 million in premiums and $5 million of unamortized deferred changes. In addition, in the Prior Period, we redeemed $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 at par. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount.

Other Income. Other income was $13 million in the Current Period and $8 million the Prior Period and consisted primarily of miscellaneous income.

Income Tax Expense. Chesapeake recorded income tax expense of $421 million and $446 million in the Current Period and the Prior Period, respectively. Our effective income tax rate was 37.7% in the Current Period and 38.0% in the Prior Period. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $80 million and $89 million in the Current Period and the Prior Period, respectively. Net income attributable to noncontrolling interests is primarily driven by the dividends paid on our CHK Utica and CHK C-T subsidiary preferred stock in addition to income or loss related to the Chesapeake Granite Wash Trust. See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of these entities.

Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board (FASB) issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We adopted this standard on January 1, 2014, and it did not have a material impact on our consolidated financial statements.

In April 2014, the FASB issued an accounting standards update that raises the threshold for a disposal or classification as held for sale to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This accounting standards update is effective for us beginning on January 1, 2015, and it is not expected to have a material impact on our consolidated financial statements.

In May 2014, the FASB issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration a company expects to receive in the exchange. The accounting standards update is effective for us beginning January 1, 2017, and we are evaluating the impact on our consolidated financial statements.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). Forward-looking statements give our current expectations or forecasts of future events. They include expected natural gas, oil and NGL production and future expenses, estimated operating costs, assumptions regarding future natural gas, oil and NGL prices, planned drilling activity, estimates of future drilling and completion and other capital expenditures (including the use of joint venture drilling carries), and anticipated sales, as well as statements concerning anticipated cash flow and liquidity, ability to comply with financial maintenance covenants and meet contractual cash commitments to third parties, debt reduction, operating and capital efficiencies, business strategy and other plans and objectives for future operations. Our ability to generate sufficient operating cash flow to fund future capital expenditures is subject to all the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Further, pending divestiture transactions are subject to closing conditions and may not be completed in the time frame anticipated or at all. Other transactions we are evaluating as we focus on our strategic priorities are subject to market conditions and other factors beyond our control. Our plans to reduce financial leverage and complexity may take longer to implement if such dispositions are delayed or do not occur as expected. Disclosures concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our 2013 Form 10-K and include:

- the volatility of natural gas, oil and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- the availability of capital on an economic basis to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- commodity derivative activities resulting in lower prices realized on natural gas, oil and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- charges incurred in connection with actions to reduce financial leverage and complexity;
- competition in the oil and gas exploration and production industry;
- drilling and operating risks, including potential environmental liabilities;
- our need to acquire adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species;
- a deterioration in general economic, business or industry conditions;
- oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow;
- adverse developments or losses from pending or future litigation and regulatory investigations;
- cyber attacks adversely impacting our operations; and
- an interruption in operations at our headquarters due to a catastrophic event.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, and we undertake no obligation to update this information except as required by applicable law. We urge you to carefully review and consider the disclosures made in this report and our other filings with the SEC that attempt to advise interested parties of the risks and factors that may affect our business.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Natural Gas, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective prices to be received for our share of production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse natural gas, oil and NGL price changes is to hedge into strengthening natural gas and oil futures markets when prices reach levels that management believes are unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, natural gas and oil storage inventory levels, industry decline rates for base production and weather trends.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps, collars and options. All of these are described in more detail below. We typically use collars, three-way collars and swaps for a large portion of the natural gas and oil price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility. In the second half of 2011 and in 2012 and 2013, we bought natural gas and oil calls to, in effect, lock in sold call positions. Due to lower natural gas, oil and NGL prices, we were able to achieve this at a low cost to us. In some cases, we deferred the payment of the premium on these trades to the related month of production. Some of our derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception and the cash settlements associated with these instruments are classified as financing cash flows in the accompanying condensed consolidated statements of cash flows.

We determine the volume potentially subject to derivative contracts by reviewing our overall estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production (risked) from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not enter into derivative contracts for volumes in excess of our forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be reversed. The actual fixed price on our derivative instruments is derived from the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price payment, resulting in a net amount due to or from the counterparty.

We review our derivative positions continuously and if future market conditions change and prices are at levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either negotiating a cash settlement with our counterparty, restructuring the position or entering into a new trade that effectively reverses the current position. The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original derivative position. Gains or losses related to closed positions will be recognized in the month of related production based on the terms specified in the original contract.

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our multi-counterparty secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 9 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the fair value measurements associated with our derivatives.

As of June 30, 2014, our natural gas and oil derivative instruments consisted of the following:

- Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call options, no payment is due from either party.
- Basis Protection Swaps: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

As of June 30, 2014, we had the following open natural gas and oil derivative instruments:

	Volume (tbtu)	Weighted Average Price Fixed ($ per mmbtu)	Call	Put	Differential	Fair Value Asset (Liability) ($ in millions)
Natural Gas:						
Swaps:						
Short-term	293	$4.21	$—	$—	$—	$(75)
3-Way Collars:						
Short-term	264	—	4.48	3.44 / 4.23	—	(28)
Long-term	71	—	4.37	3.38 / 4.17	—	1
Collars:						
Short-term	22	—	5.24	4.50	—	4
Call Options (sold):						
Short-term	279	—	6.38	—	—	(7)
Long-term	507	—	7.57	—	—	(30)
Call Options (bought)[(a)]:						
Short-term	(279)	—	6.38	—	—	(54)
Long-term	(314)	—	6.12	—	—	(104)
Basis Protection Swaps:						
Short-term	82	—	—	—	(0.49)	19
Long-term	24	—	—	—	(0.57)	(4)
Total Natural Gas						$(278)

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		Weighted Average Price				Fair Value Asset (Liability)
	Volume	Fixed	Call	Put	Differential	
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps:						
Short-term	17.1	$94.02	$—	$—	$—	$(145)
Long-term	1.2	94.21	—	—	—	(1)
3-Way Collars:						
Short-term	2.2		98.94	80.00 / 90.00		(8)
Long-term	2.2		98.94	80.00 / 90.00		(4)
Call Options (sold):						
Short-term	17.8	—	98.83	—	—	(127)
Long-term	35.5	—	100.21	—	—	(199)
Call Options (bought)(b):						
Short-term	(9.9)	—	105.43	—	—	7
Long-term	(4.5)	—	113.54	—	—	(1)
Basis Protection Swaps:						
Short-term	0.2	—	—	—	6.00	1
	Total Oil					$(477)
	Total Natural Gas and Oil					$(755)

(a) Included in the fair value are deferred premiums of $21 million, $82 million and $85 million which will be included in natural gas, oil and NGL sales as realized gains (losses) in 2014, 2015 and 2016, respectively.

(b) Included in the fair value are deferred premiums of $23 million and $13 million which will be included in natural gas, oil and NGL sales as realized gains (losses) in 2014 and 2015, respectively.

In addition to the open derivative positions disclosed above, as of June 30, 2014, we had $137 million of net derivative gains related to settled contracts for future production periods that will be recorded within natural gas, oil and NGL sales as realized gains (losses) on derivatives once they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production, based on the terms specified in the original contract as noted below.

	June 30, 2014 ($ in millions)
Short-term	$10
Long-term	127
Total	$137

The table below reconciles the changes in fair value of our natural gas and oil derivatives during the Current Period. Of the $755 million fair value liability as of June 30, 2014, $413 million related to contracts maturing in the next 12 months and $342 million related to contracts maturing after 12 months. All open derivative instruments as of June 30, 2014 are expected to mature by December 31, 2022.

	2014
	($ in millions)
Fair value of contracts outstanding, as of January 1	$(551)
Change in fair value of contracts	(562)
Fair value of new contracts when entered into	—
Contracts realized or otherwise settled	365
Fair value of contracts when closed	(7)
Fair value of contracts outstanding, as of June 30	$(755)

The change in natural gas and oil prices during the Current Period increased the liability related to our derivative instruments by $562 million. This unrealized gain is recorded in natural gas, oil and NGL sales. We settled contracts in the Current Period that were in a liability position for $365 million. The realized losses will be recorded in natural gas, oil and NGL sales in the month of related production. We terminated contracts that were in an asset position for $7 million. The realized gain is recorded in natural gas, oil and NGL sales in the month of related production.

Interest Rate Derivatives

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2014	2015	2016	2017	2018	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$—	$396	$500	$2,300	$1,015	$6,100	$10,311
Average interest rate	— %	2.75 %	3.25 %	4.42 %	5.54 %	5.83 %	5.24 %
Debt – variable rate	$—	$—	$—	$—	$—	$1,500	$1,500
Average interest rate	— %	— %	— %	— %	— %	3.48 %	3.48 %

(a) This amount does not include the discount included in debt of $272 million and interest rate derivatives of $10 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facility and our floating rate senior notes. All of our other indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

We enter into interest rate derivatives, including fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes and floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings. As of June 30, 2014, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed		Weighted Average Rate Floating[a]	Fair Value Hedge	Fair Value Asset (Liability) ($ in millions)	
Fixed to Floating:							
Swaps							
Mature 2020 – 2023	$1,050	5.97	%	1 – 3 mL 429 bp	No	$(38	)
Floating to Fixed:							
Swaps							
Mature 2014 – 2015	$900	2.06	%	1 – 6 mL	No	(10	)
						$(48	)

(a) Month LIBOR has been abbreviated "mL" and basis points has been abbreviated "bp".

In addition to the open derivative positions disclosed above, as of June 30, 2014 we had $59 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains (losses) once they are transferred from our senior note liability or within interest expense as unrealized gains (losses) over the remaining six-year term of our related senior notes.

Realized and unrealized gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations.

Foreign Currency Derivatives

In December 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as an asset of $6 million as of June 30, 2014. The euro-denominated debt in long-term debt has been adjusted to $471 million as of June 30, 2014 using an exchange rate of $1.3692 to €1.00.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake’s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). 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, 2014.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the period ended June 30, 2014, which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is currently indeterminate. See Note 5 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

July 2008 Common Stock Offering. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company's July 2008 common stock offering. The plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. Final judgment in favor of Chesapeake and the officer and director defendants was entered on June 21, 2013, and the plaintiff filed a notice of appeal on July 19, 2013 in the U.S. Court of Appeals for the Tenth Circuit. The appeal has been fully briefed and oral argument was held on May 14, 2014.

A derivative action relating to the July 2008 offering filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011 is pending. Following the denial on September 28, 2012 of its motion to dismiss and pursuant to court order, nominal defendant Chesapeake filed an answer in the case on October 12, 2012. By stipulation between the parties, the case is stayed pending resolution of the Tenth Circuit appeal of the 2009 securities class action.

2012 Securities and Shareholder Litigation. A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and its former Chief Executive Officer (CEO), Aubrey K. McClendon. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserted claims under Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company's asset monetization strategy, including liabilities associated with its VPP transactions, as well as Mr. McClendon's personal loans and the Company's internal controls. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. On April 10, 2013, the Court granted the motion, and on April 16, 2013 entered judgment against the plaintiff and dismissed the complaint with prejudice. The U.S. Court of Appeals for the Tenth Circuit affirmed the dismissal on July 8, 2014, and the time for further appeal has expired.

A related federal consolidated derivative action and an Oklahoma state court derivative action were stayed pursuant to the parties' stipulation pending resolution of the appeal in the 2012 federal securities class action. Following the affirmance of the dismissal of the 2012 securities class action, plaintiffs in the consolidated federal derivative action and Oklahoma state court derivative action advised the Company that they intend to proceed with their claims. The Company anticipates that plaintiffs will jointly file an amended consolidated complaint in the federal action, and that the stay of the Oklahoma state court action will remain in place.

On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company's directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company's officers and directors' use of the Company's fractionally owned corporate jets. On August 21, 2012, the District Court granted the Company's motion to dismiss for lack of derivative standing, and the plaintiff appealed the ruling on December 6, 2012. On May 16, 2014, the Court of Civil Appeals for the State of Oklahoma affirmed the dismissal. On July 7, 2014, plaintiffs filed a petition for writ of certiorari in the Oklahoma Supreme Court seeking review of the Court of Civil Appeals' decision.

2014 Shareholder Litigation. On April 10, 2014, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against current and former directors and officers of the Company alleging, among other things, breach of fiduciary duties, waste of corporate assets, gross mismanagement and unjust enrichment related to the Company's payment of shareholder dividends since October 2012. On July 2, 2014, the Company filed its motion to dismiss.

Regulatory Proceedings. The Company has received, from the Antitrust Division of the U.S. Department of Justice (DOJ) and certain state governmental agencies, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state laws relating to our purchase and lease of oil and gas rights in various states. Chesapeake has engaged in discussions with the DOJ and state agencies and continues to respond to such subpoenas and demands.

On March 5, 2014, the Attorney General of the State of Michigan filed a criminal complaint against Chesapeake in Michigan state court alleging misdemeanor antitrust violations and attempted antitrust violations under state law arising out of the Company's leasing activities in Michigan during 2010. On July 9, 2014, following a preliminary hearing on the complaint, as amended, the 89th District Court for Cheboygan County, Michigan ruled that one count alleging a bid-rigging conspiracy between Chesapeake and Encana Oil & Gas USA, Inc. regarding the October 2010 state lease auction would proceed to trial and dismissed claims alleging a second antitrust violation and an attempted antitrust violation. The Michigan Attorney General filed a second criminal complaint against Chesapeake on June 5, 2014 which, as amended, alleges that Chesapeake's conduct in canceling lease offers to Michigan landowners in 2010 violated the state's criminal enterprises and false pretenses felony statutes. The Court has set a preliminary hearing on this matter starting August 18, 2014.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims is immaterial to its consolidated financial statements. Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. The Company has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages for royalty underpayment in various states, including cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class.

ITEM 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under "Risk Factors" in Item 1A of our 2013 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

The following table presents information about repurchases of our common stock during the quarter ended June 30, 2014:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share[(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
April 1, 2014 through April 30, 2014	35,393	$27.16	—	—
May 1, 2014 through May 31, 2014	45,466	$28.14	—	—
June 1, 2014 through June 30, 2014	9,774	$30.73	—	—
Total	90,633	$28.04	—	—

(a) Reflects the surrender to the Company of shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan and deferred compensation plan using Chesapeake common stock that is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of Company contributions.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Effective August 5, 2014, Chesapeake filed a Restated Certificate of Incorporation with the Oklahoma Secretary of State to integrate various previously approved and filed amendments to such certificate. The Restated Certificate of Incorporation is attached as Exhibit 3.1.1 to this Quarterly Report on Form 10-Q.

ITEM 6. Exhibits

The following exhibits are filed or furnished herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake's Restated Certificate of Incorporation.					X	
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/19/2014		
4.1.1	Indenture, dated as of April 24, 2014, by and among the Company, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee.	8-K	001-13726	4.1	4/29/2014		
4.1.2	First Supplemental Indenture, dated as of April 24, 2014, to	8-K	001-13726	4.2	4/29/2014		

	Indenture dated as of April 24, 2014 with respect to Floating Rate Senior Notes due 2019.					
4.1.3	Second Supplemental Indenture, dated as of April 24, 2014, to Indenture dated as of April 24, 2014 with respect to 4.875% Senior Notes due 2022.	8-K	001-13726	4.3	4/29/2014	
10.1	Chesapeake Energy Corporation 2014 Long Term Incentive Plan.	Schedule 14A	001-13726	F	4/30/2014	
10.2	Form of Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.					X
10.3	Form of Restricted Stock Award Agreement for 2014 Long Term Incentive Plan.					X
10.4	Form of Nonqualified Stock Option Agreement for 2014 Long Term Incentive Plan.					X

10.5	Form of Performance Share Unit Award Agreement for 2014 Long Term Incentive Plan.	X	
10.6	Form of Non-Employee Director Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	X	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.	X	
31.1	Robert D. Lawler, Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X	
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X	
32.1	Robert D. Lawler, Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of		X

	2002.	
101.INS	XBRL Instance Document.	X
101.SCH	XBRL Taxonomy Extension Schema Document.	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	X

SIGNATURES

Pursuant to the requirement of Section 13 or 15(d) 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.

	CHESAPEAKE ENERGY CORPORATION
Date: August 6, 2014	By: /s/ ROBERT D. LAWLER Robert D. Lawler, President and Chief Executive Officer
Date: August 6, 2014	By: /s/ DOMENIC J. DELL’OSSO, JR. Domenic J. Dell’Osso, Jr. Executive Vice President and Chief Financial Officer

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