CHESAPEAKE ENERGY CORP
Form 10-Q
August 05, 2015
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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, 2015
[ ] 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 July 31, 2015, there were 665,366,523 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, 2015

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PART I. FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements (Unaudited)
CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2015	December 31, 2014
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$2,051	$4,108
Restricted cash	38	38
Accounts receivable, net	1,501	2,236
Short-term derivative assets ($5 and $16 attributable to our VIE)	387	879
Other current assets	254	207
Total Current Assets	4,231	7,468
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full cost accounting:		
Proved oil and natural gas properties ($488 and $488 attributable to our VIE)	62,161	58,594
Unproved properties	8,625	9,788
Other property and equipment	3,038	3,083
Total Property and Equipment, at Cost	73,824	71,465
Less: accumulated depreciation, depletion and amortization (($361) and ($251) attributable to our VIE)	(50,302)	(39,043)
Property and equipment held for sale, net	93	93
Total Property and Equipment, Net	23,615	32,515
LONG-TERM ASSETS:		
Investments	255	265
Long-term derivative assets	186	6
Other long-term assets	311	497
TOTAL ASSETS	$28,598	$40,751

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, 2015	December 31, 2014
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$1,284	$2,049
Current maturities of long-term debt, net	889	381
Accrued interest	153	150
Deferred income tax liabilities	126	207
Short-term derivative liabilities	27	15
Other current liabilities ($11 and $15 attributable to our VIE)	2,649	3,061
Total Current Liabilities	5,128	5,863
LONG-TERM LIABILITIES:		
Long-term debt, net	10,655	11,154
Deferred income tax liabilities	1,408	4,185
Long-term derivative liabilities	155	218
Asset retirement obligations, net of current portion	460	447
Other long-term liabilities	549	679
Total Long-Term Liabilities	13,227	16,683
CONTINGENCIES AND COMMITMENTS (Note 4)		
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: 665,060,856 and 664,944,232 shares issued	7	7
Paid-in capital	12,420	12,531
Retained earnings (deficit)	(6,364)	1,483
Accumulated other comprehensive loss	(131)	(143)
Less: treasury stock, at cost; 1,586,305 and 1,614,312 common shares	(36)	(37)
Total Chesapeake Stockholders' Equity	8,958	16,903
Noncontrolling interests	1,285	1,302
Total Equity	10,243	18,205
TOTAL LIABILITIES AND EQUITY	$28,598	$40,751

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 OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	($ in millions except per share data)			
REVENUES:				
Oil, natural gas and NGL	$728	$1,704	$1,813	$3,471
Marketing, gathering and compression	2,305	3,167	3,980	6,182
Oilfield services	—	281	—	545
Total Revenues	3,033	5,152	5,793	10,198
OPERATING EXPENSES:				
Oil, natural gas and NGL production	276	282	575	570
Production taxes	34	72	62	122
Marketing, gathering and compression	2,096	3,166	3,796	6,147
Oilfield services	—	212	—	431
General and administrative	69	90	125	169
Restructuring and other termination costs	(4)	33	(14)	26
Provision for legal contingencies	334	—	359	—
Oil, natural gas and NGL depreciation, depletion and amortization	601	661	1,285	1,288
Depreciation and amortization of other assets	34	79	69	157
Impairment of oil and natural gas properties	5,015	—	9,991	—
Impairments of fixed assets and other	84	40	88	60
Net (gains) losses on sales of fixed assets	1	(93)	4	(115)
Total Operating Expenses	8,540	4,542	16,340	8,855
INCOME (LOSS) FROM OPERATIONS	(5,507)	610	(10,547)	1,343
OTHER INCOME (EXPENSE):				
Interest expense	(71)	(27)	(122)	(66)
Losses on investments	(17)	(24)	(24)	(45)
Net gain on sales of investments	—	—	—	67
Losses on purchases of debt	—	(195)	—	(195)
Other income (expense)	(1)	7	5	13
Total Other Expense	(89)	(239)	(141)	(226)
INCOME (LOSS) BEFORE INCOME TAXES	(5,596)	371	(10,688)	1,117
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	(6)	5	(6)	8
Deferred income taxes	(1,500)	136	(2,872)	413
Total Income Tax Expense (Benefit)	(1,506)	141	(2,878)	421
NET INCOME (LOSS)	(4,090)	230	(7,810)	696
Net income attributable to noncontrolling interests	(18)	(39)	(37)	(80)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(4,108)	191	(7,847)	616
Preferred stock dividends	(43)	(43)	(86)	(86)
Earnings allocated to participating securities	—	(3)	—	(12)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$(4,151)	$145	$(7,933)	$518

EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$(6.27)	$0.22	$(11.99)	$0.79
Diluted	$(6.27)	$0.22	$(11.99)	$0.78
CASH DIVIDEND DECLARED PER COMMON SHARE	$—	$0.0875	$0.0875	$0.1750
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	662	659	662	658
Diluted	662	659	662	760

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 COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	($ in millions)			
NET INCOME (LOSS)	$(4,090)	$230	$(7,810)	$696
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:				
Unrealized gains (losses) on derivative instruments, net of income tax expense (benefit) of $0 , $1, ($1) and $3	—	—	(1)	3
Reclassification of (gains) losses on settled derivative instruments, net of income tax expense (benefit) of $2, $4, $9 and $10	3	(1)	13	10
Reclassification of (gains) losses on investment, net of income tax expense (benefit) of $0, $0, $0 and ($3)	—	—	—	(5)
Other Comprehensive Income (Loss)	3	(1)	12	8
COMPREHENSIVE INCOME (LOSS)	(4,087)	229	(7,798)	704
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(18)	(39)	(37)	(80)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(4,105)	$190	$(7,835)	$624

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,	
	2015	2014
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$(7,810)	$696
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,354	1,445
Deferred income tax expense (benefit)	(2,872)	413
Derivative (gains) losses, net	(344)	542
Cash receipts (payments) on derivative settlements, net	631	(323)
Stock-based compensation	43	40
Impairment of oil and natural gas properties	9,991	—
Net (gains) losses on sales of fixed assets	4	(115)
Impairments of fixed assets and other	81	51
Losses on investments	24	45
Net gains on sales of investments	—	(67)
Losses on purchases of debt	—	61
Restructuring and other termination costs	(14)	24
Provision for legal contingencies	359	—
Other	69	71
Changes in assets and liabilities	(779)	(240)
Net Cash Provided By Operating Activities	737	2,643
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(2,168)	(1,996)
Acquisitions of proved and unproved properties	(266)	(356)
Proceeds from divestitures of proved and unproved properties	14	248
Additions to other property and equipment	(93)	(620)
Proceeds from sales of other property and equipment	7	713
Additions to investments	(6)	(5)
Proceeds from sales of investments	—	239
Other	—	(3)
Net Cash Used In Investing Activities	(2,512)	(1,780)

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 – (Continued)
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
	($ in millions)	
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	—	857
Payments on credit facilities borrowings	—	(1,239)
Proceeds from issuance of senior notes, net of discount and offering costs	—	2,966
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)
Cash paid for common stock dividends	(118)	(117)
Cash paid for preferred stock dividends	(86)	(86)
Cash paid on financing derivatives	—	(32)
Cash held and retained by SSE at spin-off	—	(8)
Distributions to noncontrolling interest owners	(57)	(105)
Other	(21)	—
Net Cash Used In Financing Activities	(282)	(238)
Net increase (decrease) in cash and cash equivalents	(2,057)	625
Cash and cash equivalents, beginning of period	4,108	837
Cash and cash equivalents, end of period	$2,051	$1,462

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

SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$65	$88
Income taxes paid, net of refunds received	$60	$13
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$(46)	$(125)
Change in accrued acquisitions of proved and unproved properties	$(31)	$(60)

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 STOCKHOLDERS' EQUITY
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
	($ 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	12,531	12,446
Stock-based compensation	40	23
Exercise of stock options	—	23
Dividends on common stock	(59)	—
Dividends on preferred stock	(86)	—
Increase (decrease) in tax benefit from stock-based compensation	(6)	3
Balance, end of period	12,420	12,495
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	1,483	688
Net income (loss) attributable to Chesapeake	(7,847)	616
Dividends on common stock	—	(117)
Dividends on preferred stock	—	(86)
Spin-off of oilfield services business (Note 14)	—	(268)
Balance, end of period	(6,364)	833
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(143)	(162)
Hedging activity	12	13
Investment activity	—	(5)
Balance, end of period	(131)	(154)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(37)	(46)
Purchase of 28,298 and 15,532 shares for company benefit plans	—	—
Release of 56,305 and 300,034 shares from company benefit plans	1	5
Balance, end of period	(36)	(41)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	8,958	16,202
NONCONTROLLING INTERESTS:		
Balance, beginning of period	1,302	2,145
Net income attributable to noncontrolling interests	37	80
Distributions to noncontrolling interest owners	(54)	(102)
Balance, end of period	1,285	2,123
TOTAL EQUITY	$10,243	$18,325

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

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 were 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 were 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, 2015 (the "Current Quarter" and the “Current Period”, respectively) and the three and six months ended June 30, 2014 (the "Prior Quarter" and the “Prior Period”, respectively). Chesapeake's annual report on Form 10-K for the year ended December 31, 2014 ("2014 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 statement 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.

2. 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 3 for further discussion of our contingent convertible senior notes.

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, shares of the following securities and associated adjustments to net income, representing dividends on preferred stock and allocated earnings on participating securities, were excluded from the calculation of diluted EPS as the effect was antidilutive.

	Net Income Adjustments	Shares
	($ in millions)	(in millions)
Three Months Ended June 30, 2015		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$21	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
Participating securities	$—	1
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
Participating securities	$3	3

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

	Net Income Adjustments ($ in millions)	Shares (in millions)
Six Months Ended June 30, 2015		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$43	59
5.75% cumulative convertible preferred stock (series A)	$32	42
5.00% cumulative convertible preferred stock (series 2005B)	$5	6
4.50% cumulative convertible preferred stock	$6	6
Participating securities	$—	2
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
Participating securities	$11	3

For the Prior Period, the following outstanding equity securities convertible into common stock were included in the calculation of diluted EPS. A reconciliation of basic EPS and diluted EPS for the Prior Period is as follows:

	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
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

3. Debt

Our long-term debt consisted of the following as of June 30, 2015 and December 31, 2014:

	June 30, 2015	December 31, 2014
	($ in millions)	
3.25% senior notes due 2016	$500	$500
6.25% euro-denominated senior notes due 2017[(a)]	384	416
6.5% senior notes due 2017	660	660
7.25% senior notes due 2018	669	669
Floating rate senior notes due 2019	1,500	1,500
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	1,500
5.75% senior notes due 2023	1,100	1,100
2.75% contingent convertible senior notes due 2035[(b)]	396	396
2.5% contingent convertible senior notes due 2037[(b)]	1,168	1,168
2.25% contingent convertible senior notes due 2038[(b)]	347	347
Revolving credit facility	—	—
Discount on senior notes[(c)]	(188)	(231)
Interest rate derivatives[(d)]	8	10
Total debt, net	11,544	11,535
Less current maturities of long-term debt, net[(e)]	(889)	(381)
Total long-term debt, net	$10,655	$11,154

(a) The principal amount shown is based on the exchange rate of $1.1147 to €1.00 and $1.2098 to €1.00 as of June 30, 2015 and December 31, 2014, respectively. See Note 8 for information on our related foreign currency derivatives.

(b) The repurchase, conversion, contingent interest and redemption provisions of our contingent convertible senior notes are as follows:

Holders' Demand Repurchase Rights. 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 holders of our 2.75% Contingent Convertible Senior Notes due 2035 could exercise their individual demand repurchase rights on November 15, 2015, which would require us to repurchase all or a portion of the principal amount of the notes.

Optional Conversion by Holders. At the holder's option, prior to maturity under certain circumstances, the notes are convertible into cash and, if applicable, shares of our common stock using a net share settlement process. One 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. During the specified period in the second quarter of 2015, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes 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 2015 under this provision.

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

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 during 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 the principal amount.

Contingent Interest. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years during certain periods if the average trading price of the notes exceeds the threshold defined in the indenture.

The holders’ demand repurchase dates, the common stock price conversion threshold amounts (as adjusted to give effect to 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	Holders' Demand Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$45.14	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$59.44	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$100.35	June 14, 2019

Optional Redemption by the Company. We may redeem the contingent 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.

(c) Discount as of June 30, 2015 and December 31, 2014 included $181 million and $224 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(d) See Note 8 for further discussion related to these instruments.

(e) As of June 30, 2015, current maturities of long-term debt, net includes the carrying amount of our 3.25% Senior Notes due March 2016 and 2.75% Contingent Convertible Senior Notes due 2035. As discussed in footnote (b) above, the holders of our 2.75% Contingent Convertible Senior Notes due 2035 could exercise their individual demand repurchase rights on November 15, 2015, which would require us to repurchase all or a portion of the principal amount of the notes. As of June 30, 2015 and December 31, 2014, current maturities of long-term debt, net reflects $7 million and $15 million, respectively, of discount associated with the equity component of the 2.75% Contingent Convertible Senior Notes due 2035.

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, 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.

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.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York against The Bank of New York Mellon Trust Company, N.A., the indenture trustee for the 6.775% Senior Notes due 2019 (the 2019 Notes). The Company sought and ultimately obtained a judgment declaring that the notice it issued on March 15, 2013 to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) was timely and effective for that redemption pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes. In May 2013, as a result of that ruling, the 2019 Notes were redeemed at par. In November 2014, the U.S. Court of Appeals for the Second Circuit, on appeal by the indenture trustee, reversed the District Court's declaratory judgment and held that the notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose. The Court of Appeals remanded the case to the District Court for a determination whether the redemption notice triggered a redemption at the make-whole price specified in the indenture, instead of at par. The Company sought a rehearing by the Court of Appeals en banc in December 2014, and that petition was denied on February 6, 2015. On February 13, 2015, the indenture trustee moved the District Court for entry of a judgment requiring the Company to pay the make-whole price, as defined in the indenture, less the par amount paid in the 2013 redemption plus prejudgment interest from the redemption date. On March 20, 2015, the Company filed its opposition to the Trustee's motion and cross-moved for a judgment requiring the Company to pay restitution in an amount that would disgorge the benefit the Company achieved from refinancing the 2019 Notes in 2013 and that would return the parties to the economic positions they would have been in if the par redemption had never taken place. The District Court held argument on the motion and cross-motion on May 1, 2015. On July 10, 2015, the District Court granted the Trustee's motion and denied the Company's cross-motion and entered an amended judgment on July 17, 2015 awarding the Trustee $380 million plus prejudgment interest in the amount of $59 million. The Company filed a notice of appeal on July 27, 2015 and posted a supersedeas bond to stay execution of the judgment while appellate proceedings are pending.

Revolving Credit Facility

In December 2014, we entered into a five-year $4.0 billion senior unsecured revolving credit facility to use for general corporate purposes. The credit facility replaced our then-existing $4.0 billion senior secured revolving credit facility. The aggregate commitments under the facility may be increased up to an additional $1.0 billion, and the December 2019 maturity date may be extended for two one-year periods at our request and with the consent of the participating lenders. As of June 30, 2015, we had no outstanding borrowings under the facility and utilized $15 million of the facility for various letters of credit. Borrowings under the facility are currently unsecured; however, we will be required to provide collateral and the facility will be subject to a borrowing base if our credit rating declines to Ba3 (Moody's Investors Services, Inc.) or BB- (Standard & Poor's Ratings Services) or lower.

Revolving loans under the credit facility bear interest at a fluctuating rate per annum equal to the highest of (i) the federal funds effective rate plus 0.5%, (ii) the administrative agent's prime rate or (iii) the London interbank offer rate (LIBOR) for a one-month interest period plus 1.0% (alternative base rate (ABR) loans), and/or LIBOR rates (LIBOR loans), at our election, plus an applicable margin rate depending on our credit rating (currently 0.625% per annum for ABR loans and 1.625% per annum for LIBOR loans). The terms of the credit facility include covenants limiting, among other things, the ability of the Company and its restricted subsidiaries to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates. In addition, the credit facility requires us to maintain, as of the last day of each fiscal quarter, (i) a net debt to capitalization ratio (as defined in the credit agreement) that does not exceed 65%; and (ii) a leverage ratio (net debt to consolidated EBITDA, as defined in the credit agreement) that does not exceed 4.0 to 1.0; provided, however, that the leverage ratio will not apply during any period in which our credit rating, as determined by either Moody's Investors Services, Inc. or Standard & Poor's Rating Services, meets certain investment grade thresholds, as defined in the credit agreement.

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Our credit facility is fully and unconditionally guaranteed, on a joint and several basis, by certain of our material subsidiaries. The credit agreement includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to indebtedness in an aggregate principal amount of $125 million or more; bankruptcy; judgments involving liability of $125 million or more that are not paid; and ERISA events. Many events of default are subject to customary notice and cure periods.

Spin-Off Debt Transactions

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). In the Prior Quarter, 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 then-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 consolidated balance sheet as of June 30, 2014. See Note 14 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 would include borrowings under our revolving credit facility (which was undrawn as of June 30, 2015 and December 31, 2014), 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, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		($ in millions)		
Short-term debt (Level 1)	$889	$892	$381	$396
Long-term debt (Level 1)	$10,647	$10,286	$11,144	$11,656

4. 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 Litigation. 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. On appeal, the U.S. Court of Appeals for the Tenth Circuit affirmed the dismissal on August 8, 2014 and denied the plaintiffs’ petition for rehearing on November 12, 2014. On April 10, 2015, the plaintiffs filed a writ of certiorari with the United States Supreme Court.
Shareholder Derivative Litigation. A federal consolidated derivative action and an Oklahoma state court derivative action were stayed in 2012 pending resolution of a related, previously reported putative federal securities class action. The shareholder derivative actions allege breaches of fiduciary duty, among other things, related to the former CEO’s personal financial practices and purported conflicts of interest, and the Company’s accounting for volumetric production payments. With the dismissal of the federal securities class action now affirmed (in July 2014), the parties stipulated to continue the stay of the Oklahoma state court derivative action while the plaintiffs pursue their claims in the federal consolidated derivative action. The plaintiffs filed a consolidated derivative complaint on October 31, 2014 and an amended consolidated derivative complaint on February 12, 2015. Chesapeake filed its motion to dismiss on February 23, 2015.
Regulatory Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and gas rights in various states. The Company also has received DOJ and state subpoenas seeking information on the Company’s royalty payment practices. Chesapeake has engaged in discussions with the DOJ and state agency representatives 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 in the same court on June 5, 2014 which, as amended, alleged that Chesapeake’s conduct in canceling lease offers to Michigan landowners in 2010 violated the state’s criminal enterprises and false pretenses felony statutes. In resolution of both criminal complaints and with no admission of wrongdoing, on April 24, 2015, the Company entered a plea of no contest to one count of misdemeanor attempted antitrust violation and one count of misdemeanor false pretenses. The plea has been taken under advisement for a period of 11 months by the Court and will be dismissed if Chesapeake fulfills the terms of a settlement agreement with the Attorney General. As part of the settlement, Chesapeake will contribute no more than $25 million to a compensation fund established to compensate Michigan landowners for unfunded oil and gas leases in 2010.
Redemption of 2019 Notes. See Note 3 for a description of pending litigation regarding our redemption in May 2013 of our 2019 Notes. As a result of the reversal of the trial court’s decision in our declaratory judgment action against the indenture trustee, we accrued a loss contingency of $100 million for this matter in the 2014 fourth quarter, and we accrued an additional $339 million in the Current Quarter as a result of the judgment on remand entered on July 17, 2015.
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 oil and natural gas 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 will not have a material adverse effect on the Company’s consolidated financial position, results of operations or cash flows.
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 natural gas liquids (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, but not limited to, Oklahoma, Texas, Pennsylvania, Ohio, Louisiana and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ and state subpoenas seeking information on the Company’s royalty payment practices.
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 putative class action filed in November 2010 in the District Court of Beaver County, Oklahoma 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. We and the named plaintiff participated in mediation concerning the claims asserted in the putative class action litigation, and in the Current Period we negotiated a settlement requiring the Company to pay $119 million cash to compensate the putative settlement class for alleged past royalty underpayments in exchange for the release of claims for the ten-year period ended December 31, 2014. Following a fairness hearing, the District Court certified the settlement class and approved the $119 million settlement on July 3, 2015. The Company reduced its prior settlement accrual to $114 million in the Current Quarter to reflect potential claimants that have opted out of the settlement. Although Chesapeake believes its royalty calculation and payment methodologies are appropriate under Oklahoma oil and gas law and denies that it committed any acts or omissions giving rise to any liability, it also believes that settlement is in the best interest of the Company considering the questions of law and fact involved and the uncertainty of continued litigation.
Chesapeake is also defending lawsuits alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order from the Texas Multidistrict Litigation Panel to transfer a substantial portion of these lawsuits filed since June 2014 to the 348th District Court of Tarrant County for pre-trial purposes. These lawsuits, which are primarily related to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. In addition to allegations of breach of contract, a number of these lawsuits allege fraud, conspiracy, joint venture and antitrust violations by Chesapeake. Chesapeake expects that additional lawsuits will be filed by new plaintiffs making similar allegations. The lawsuits seek direct damages in varying amounts, together with exemplary damages, attorneys’ fees, costs and interest. Chesapeake believes its royalty calculations and payment practices were appropriate and has not accrued a loss contingency with respect to the multidistrict litigation.
Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed 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 cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and one of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws.
We believe losses are reasonably possible in certain of the other pending royalty cases for which we have not accrued a loss contingency, 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. 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 future 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 Contingencies

The nature of the oil and gas 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

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 oil, natural gas and NGL sales prices used in our proved reserves estimates.

In addition, we have entered into long-term agreements for certain natural gas gathering and related services within specified acreage dedication areas in exchange for cost-of-service based fees redetermined annually or tiered fees based on volumes delivered relative to scheduled volumes. Future gathering fees will vary depending on the applicable agreement. Two of these agreements, one for production in the Anadarko Basin in northwestern Oklahoma and the Texas panhandle and the other for production in the Haynesville/Bossier Shales in northwestern Louisiana, contain cost-of-service based fees that are redetermined annually through 2019 and 2020, respectively. The annual upward or downward fee adjustment for these two contracts is capped at 15% of the then-current fees at the time of redetermination. To the extent the actual rate of return on capital expended by the counterparty over the term of the agreement differs from the applicable rate of return, a payment is due to (from) the midstream service company.

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

	June 30, 2015
	($ in millions)
2015	$914
2016	1,936
2017	1,941
2018	1,723
2019	1,437
2020 – 2099	6,227
Total	$14,178

Drilling Contracts

We have contracts with various drilling contractors, including those entered into with SSE in connection with the spin-off of our oilfield services business in June 2014, to utilize drilling services with terms ranging from three months to three years at market-based pricing. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2015, the aggregate undiscounted minimum future payments under these drilling service commitments were approximately $353 million.

Pressure Pumping Contracts

In connection with the spin-off of our oilfield services business in June 2014, we entered into an agreement with a subsidiary of SSE for pressure pumping 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 provide the overall quality of service provided by similar service providers. As of June 30, 2015, the aggregate undiscounted minimum future payments under this agreement were approximately $185 million.

Drilling Commitments

We have committed to drill wells for the benefit of Chesapeake Granite Wash Trust. See Noncontrolling Interests in Note 6 for discussion of this commitment.

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 volumetric production payment (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 9 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Total S.A. (see Note 9), 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 as of future measurement dates.

Other Commitments

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc. (Sundrop), 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, 2015, 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 10 for further discussion of this investment.

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging for, 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 and/or other specified matters. 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 entering into or consummating a particular transaction. For divestitures of oil and gas properties, our purchase and sale agreements may require the return of a portion of the proceeds we receive as a result of uncured title defects.

Certain of our oil and natural gas 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 these interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to these interests. See Note 9 for further discussion of our VPP transactions.

While executing our strategic priorities, we have incurred certain cash charges, 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, we may take certain actions that reduce financial leverage and complexity, and we may incur additional cash and noncash charges.

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5. Other Liabilities

Other current liabilities as of June 30, 2015 and December 31, 2014 are detailed below.

	June 30, 2015	December 31, 2014
	($ in millions)	
Revenues and royalties due others	$757	$1,176
Accrued drilling and production costs	327	385
Joint interest prepayments received	202	189
Accrued compensation and benefits	237	344
Other accrued taxes	130	55
Accrued dividends	43	101
Bank of New York Mellon legal accrual	439	100
Oklahoma royalty settlement	114	119
Other	400	592
Total other current liabilities	$2,649	$3,061

Other long-term liabilities as of June 30, 2015 and December 31, 2014 are detailed below.

	June 30, 2015	December 31, 2014
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$205	$220
CHK C-T ORRI conveyance obligation[b]	128	135
Financing obligations	29	30
Unrecognized tax benefits	46	45
Other	141	249
Total other long-term liabilities	$549	$679

(a) $20 million and $14 million of the total $225 million and $234 million obligations are recorded in other current liabilities as of June 30, 2015 and December 31, 2014, respectively. See Noncontrolling Interests in Note 6 for further discussion of the conveyance obligation.

(b) $28 million and $23 million of the total $156 million and $158 million obligations are recorded in other current liabilities as of June 30, 2015 and December 31, 2014, respectively. See Noncontrolling Interests in Note 6 for further discussion of the conveyance obligation.

6. Equity

Common Stock

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

	Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Shares issued as of January 1	664,944	666,192
Restricted stock issuances (net of forfeitures and cancellations)[a]	103	(2,019)
Stock option exercises	14	1,268
Shares issued as of June 30	665,061	665,441

(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 shares of common stock were previously issued on the date the RSAs were granted. We refer to RSAs and RSUs collectively as restricted stock.

Preferred Stock

The following reflects the shares outstanding of our preferred stock for the Current Period and the Prior Period:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2015 and 2014 and shares outstanding as of June 30, 2015 and 2014	1,497	1,100	2,559	2,096

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 exists after giving effect to the dividends. To the extent retained earnings are insufficient to fund the distributions, dividend declarations are accounted for as a reduction to paid-in capital.

In July 2015, our Board of Directors determined to eliminate quarterly cash dividends on our common stock. 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.

	Cash Flow Hedges	Investments	Net Change
	($ in millions)		
Balance, December 31, 2014	$(143)	$—	$(143)
Other comprehensive income before reclassifications	(1)	—	(1)
Amounts reclassified from accumulated other comprehensive income	13	—	13
Net other comprehensive income	12	—	12
Balance, June 30, 2015	$(131)	$—	$(131)
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)

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	Amounts Reclassified
		($ in millions)
Three Months Ended June 30, 2015		
Net losses on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$3
Total reclassifications for the period, net of tax		$3
Three Months Ended June 30, 2014		
Net gains on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$(1)
Total reclassifications for the period, net of tax		$(1)
Six Months Ended June 30, 2015		
Net losses on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$13
Total reclassifications for the period, net of tax		$13
Six Months Ended June 30, 2014		
Net losses on cash flow hedges:		

Commodity contracts	Oil, natural gas and NGL revenues	$10	
Investments:			
Sale of investment	Net gain on sale of investment	(5	)
Total reclassifications for the period, net of tax		$5	

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 oil and natural gas assets in our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our revolving 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, 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. Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. CHK C-T is required to retain an amount of cash equal to the next two quarters of preferred dividend payments. The amount reserved, approximately $38 million as of June 30, 2015 and December 31, 2014, was reflected as restricted cash on our condensed consolidated balance sheets. 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 to drill and complete a minimum cumulative total of (i) 162.5 net wells by June 30, 2014 and (ii) 175 net wells by December 31, 2014. The drilling commitment was suspended in January 2015.

The CHK C-T investors' right to receive, proportionately, a 3.75% ORRI in CHK C-T wells 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. We did not meet the 2014 ORRI conveyance commitment. However, in no event are we required to deliver to investors more than a total ORRI of 3.75% in the contributed wells and 1,000 future net wells. As of June 30, 2015, we had drilled 190 net wells. The obligation to deliver future ORRIs, which runs through the first quarter of 2025, has been recorded as a liability that 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 oil and natural gas properties.

As of June 30, 2015 and December 31, 2014, $1.015 billion of noncontrolling interests on our condensed consolidated balance sheets was attributable to CHK C-T. For the Current Quarter and the Prior Quarter, income of $19 million was attributable to the noncontrolling interests of CHK C-T and for the Current Period and the Prior Period, income of $38 million was attributable to the noncontrolling interests of CHK C-T.

On June 30, 2015, we entered into an agreement to sell all of the properties held by CHK C-T to FourPoint Energy, LLC (FourPoint) for approximately $575 million. We will use the consideration from the sale and cash held by CHK C-T, to repurchase the outstanding preferred shares in CHK C-T, subject to customary adjustments to the purchase price and certain indemnity obligations in connection with the sale. Upon closing of the transaction, we will eliminate the noncontrolling interest and ORRI obligation on our condensed consolidated balance sheet, approximately $75

million in annual preferred dividend payments and all related future drilling and ORRI commitments attributable to CHK C-T. We expect this transaction to close in the 2015 third quarter.
Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale oil and natural gas assets. 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.

In July 2014, we repurchased all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders for approximately $1.254 billion, or approximately $1,189 per share including accrued dividends. The $447 million difference between the cash paid for the preferred shares and the carrying value of the noncontrolling interest acquired was reflected in retained earnings and as a reduction to net income available to common stockholders for purposes of our EPS computations. 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 eliminated our obligation 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.

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 through 2023. However, in no event are we 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 the 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 the remaining ORRIs once we have drilled a minimum of 1,300 net wells. As of June 30, 2015, we had drilled 463 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 oil and natural gas 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 our ORRI conveyance commitments as of December 31, 2013 and 2014.

In the Prior Quarter and the Prior Period, income of approximately $19 million and $37 million, respectively, was attributable to the noncontrolling interests of CHK Utica.

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 Trust's initial public offering, 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 is not 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 recoverable by the Trust under the lien was limited to $263 million initially and is proportionately reduced as we fulfill our drilling obligation over time. As of June 30, 2015 and 2014, we had drilled or caused to be drilled approximately 104 and 93 development wells, respectively, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $32 million and $55 million, respectively.

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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 the quarter. If there is not sufficient cash to fund a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units is reduced or eliminated for the 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 12 quarters. 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 the quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold is to be paid to Trust unitholders, including Chesapeake, on a pro rata basis. Through June 30, 2015, no incentive distributions had been made. 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 this 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 2014 – February 2015	June 1, 2015	$0.3899	$—
September 2014 – November 2014	March 2, 2015	$0.4496	$—
December 2013 – February 2014	May 30, 2014	$0.6454	$—
September 2013 – November 2013	March 3, 2014	$0.6624	$—

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 consolidated in our condensed consolidated financial statements. As of June 30, 2015 and December 31, 2014, $271 million and $287 million, respectively, of noncontrolling interests on our condensed consolidated balance sheets were attributable to the Trust. Net income (loss) attributable to the Trust's noncontrolling interests is presented in our condensed consolidated statements of operations as a loss of approximately $1 million in the Current Quarter, income of approximately $2 million in the Prior Quarter, a loss of approximately $1 million in the Current Period and income of approximately $7 million in the Prior Period. See Note 11 for further discussion of VIEs.

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7. Share-Based Compensation

Chesapeake’s share-based compensation program consists of restricted stock, stock options and performance share units (PSUs) granted to employees and common stock 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 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, if paid, on unvested shares. A summary of the changes in unvested restricted stock during the Current Period is presented below.

	Shares of Unvested Restricted Stock (in thousands)	Weighted Average Grant Date Fair Value
Unvested restricted stock as of January 1, 2015	10,091	$21.20
Granted	6,918	$14.03
Vested	(2,651)	$16.79
Forfeited	(374)	$15.28
Unvested restricted stock as of June 30, 2015	13,984	$18.65

The aggregate intrinsic value of restricted stock that vested during the Current Period was approximately $45 million based on the stock price at the time of vesting.

As of June 30, 2015, there was approximately $180 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 2.21 years.

The vesting of certain restricted stock grants may result in state and federal income tax benefits, or reductions in these 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 reductions in tax benefits related to restricted stock of a nominal amount and $6 million, respectively, and during the Prior Quarter and the Prior Period, we recognized excess tax benefits related to restricted stock of a nominal amount and $3 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 of stock options to certain officers 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.

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 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	4.5
Volatility	39.91 %

Risk-free interest rate	1.33	%
Dividend yield	1.91	%

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The following table provides information related to stock option activity for 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, 2015	4,599	$19.55	7.03	$5
Granted	1,208	$18.37		
Exercised	(14)	$18.13		$—
Expired	(213)	$18.54		
Forfeited	—	$—		
Outstanding at June 30, 2015	5,580	$19.33	6.39	$—
Exercisable at June 30, 2015	2,169	$19.44	5.59	$—

(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, 2015, there was $13 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.02 years.

The vesting of certain stock option grants may result in state and federal income tax benefits, or reductions in these 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 a reduction in tax benefits related to stock options of nominal amounts, and during the Prior Quarter and the Prior Period, we recognized nominal amounts of excess tax benefits related to stock options. Each adjustment was recorded to additional paid-in capital and deferred income taxes.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	($ in millions)			
General and administrative expenses	$12	$11	$24	$24
Oil and natural gas properties	8	9	15	16
Oil, natural gas and NGL production expenses	6	5	10	8
Marketing, gathering and compression expenses	2	1	3	3
Oilfield services expenses	—	3	—	5
Total	$28	$29	$52	$56

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Liability-Classified Awards

Performance Share Units. In 2013, 2014 and 2015, we granted PSUs to senior management that vest ratably over their respective terms and 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 total shareholder return (TSR) and, for certain of the awards, operational performance goals such as finding and development costs and production and proved reserve growth.

For PSUs granted in 2013, the TSR component can range from 0% to 125% of base salary, 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 PSUs granted in 2015, the TSR component can range from 0% to 100%, and each of the two operational components can range from 0% to 50% resulting in a maximum total payout of 200%. The payout percentage for these PSUs is capped at 100% if the Company's absolute TSR is less than zero. Compensation expense associated with PSU grants is recognized over the service period based on the graded-vesting method. The number of units settled is dependent upon the Company's estimates of the underlying performance measures. The Company utilized the Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs:

Volatility	40.12	%
Risk-free interest rate	0.95	%
Dividend yield for value of awards	1.91	%

The following table presents a summary of our 2013, 2014 and 2015 PSU awards:

	Units	Fair Value as of Grant Date	Fair Value[a]	Liability for Vested Amount[a]
		($ in millions)		
2013 Awards:				
Payable 2016	1,701,941	$35	$13	$12
2014 Awards:				
Payable 2017	609,637	$16	$1	$1
2015 Awards:				
Payable 2018	696,683	$13	$5	$2

(a) As of June 30, 2015.

PSU Compensation. We recognized the following compensation costs (credits) related to PSUs for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	($ in millions)			
General and administrative expenses	$(4)	$11	$(14)	$10
Restructuring and other termination costs	(5)	15	(15)	6
Marketing, gathering and compression	—	1	(1)	1
Oil and natural gas properties	—	2	(1)	3

Total	$(9)	$29	$(31)	$20

Effect of the Spin-off on Share-Based Compensation

The employee matters agreement entered into in connection with the spin-off of our oilfield services business (see Note 14) addresses the treatment of holders of Chesapeake stock options, restricted stock and PSUs. 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 ceased to participate in benefit plans sponsored or maintained by Chesapeake as of the spin-off date. In addition, the employee matters agreement provides that as of the spin-off date, each party is responsible for the compensation of its current employees and for all liabilities relating to its former employees, as determined by their respective employer on the date of termination.

8. Derivative and Hedging Activities

Chesapeake uses commodity derivative instruments to secure attractive pricing and margins on its share of 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 commodity 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.

Oil and Natural Gas Derivatives

As of June 30, 2015 and December 31, 2014, our oil and natural gas 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 the excess on sold call options, and Chesapeake receives the 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.
- 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.

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The estimated fair values of our oil and natural gas derivative instrument assets (liabilities) as of June 30, 2015 and December 31, 2014 are provided below.

	June 30, 2015		December 31, 2014	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Oil (mmbbl):				
Fixed-price swaps	7.4	$196	12.5	$471
Three-way collars	2.2	21	4.4	40
Call options	27.9	(26)	35.8	(89)
Basis protection swaps	4.5	4	—	—
Total oil	42.0	$195	52.7	$422
Natural gas (tbtu):				
Fixed-price swaps	260	$135	275	$281
Three-way collars	71	51	207	165
Call options	193	(128)	193	(170)
Basis protection swaps	80	5	60	23
Total natural gas	604	$63	735	$299
Total estimated fair value		$258		$721

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, 2015 and December 31, 2014, 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 derivatives associated with our long-term debt as of June 30, 2015 and December 31, 2014 was $400 million and $850 million, respectively. The estimated fair value of our interest rate derivative liabilities as of June 30, 2015 and December 31, 2014 was a nominal amount and $17 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 $8 million in net gains related to these 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 sheets as liabilities of $88 million and $53 million as of June 30, 2015 and December 31, 2014, respectively. The euro-denominated debt in long-term debt has been adjusted to $384 million as of June 30, 2015, using an exchange rate of $1.1147 to €1.00.

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Supply Contract Derivatives

From time to time and in the normal course of business, our marketing subsidiary enters into supply contracts under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas thereby creating an embedded derivative requiring bifurcation. As of June 30, 2015, two supply contracts comprise our supply contract derivatives.

In the Current Quarter, we were required to bifurcate a derivative embedded within one of our supply contracts. Under this contract, we are committed to supply approximately 90,000 mmbtu per day of natural gas through March 2025. In the Current Quarter and the Current Period, we recorded revenues of approximately $27 million for settlements of this embedded derivative. As of June 30, 2015, the bifurcated derivative was measured to fair value, which resulted in a $221 million unrealized gain. Both settlements and mark-to market gains (losses) are included in marketing, gathering and compression revenues in our condensed consolidated statements of operations.

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, 2015 and December 31, 2014 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
	($ in millions)		
As of June 30, 2015			
Commodity Contracts:			
Short-term derivative asset	$426	$(74)	$352
Short-term derivative liability	(101)	74	(27)
Long-term derivative liability	(67)	—	(67)
Total commodity contracts	258	—	258
Interest Rate Contracts:			
Short-term derivative liability	—	—	—
Total interest rate contracts	—	—	—
Foreign Currency Contracts:[(a)]			
Long-term derivative liability	(88)	—	(88)
Total foreign currency contracts	(88)	—	(88)
Supply Contracts:			
Short-term derivative asset	35	—	35
Long-term derivative asset	186	—	186
Total supply contracts	221	—	221

Total derivatives	$391	$—	$391

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Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
As of December 31, 2014			
Commodity Contracts:			
Short-term derivative asset	$974	$(95)	$879
Long-term derivative asset	16	(10)	6
Short-term derivative liability	(105)	95	(10)
Long-term derivative liability	(163)	10	(153)
Total commodity contracts	722	—	722
Interest Rate Contracts:			
Short-term derivative liability	(5)	—	(5)
Long-term derivative liability	(12)	—	(12)
Total interest rate contracts	(17)	—	(17)
Foreign Currency Contracts:[(a)]			
Long-term derivative liability	(53)	—	(53)
Total foreign currency contracts	(53)	—	(53)
Total derivatives	$652	$—	$652

(a) Designated as cash flow hedging instruments.

As of June 30, 2015 and December 31, 2014, we did not have any cash collateral balances for these derivatives.

Effect of Derivative Instruments – Condensed Consolidated Statements of Operations

The components of oil, natural gas 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,	
	2015	2014	2015	2014
	($ in millions)			
Oil, natural gas and NGL sales	$776	$1,917	$1,700	$4,065
Gains (losses) on undesignated oil and natural gas derivatives	(43)	(210)	135	(574)
Losses on terminated cash flow hedges	(5)	(3)	(22)	(20)
Total oil, natural gas and NGL sales	$728	$1,704	$1,813	$3,471

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The components of marketing, gathering and compression 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,	
	2015	2014	2015	2014
	($ in millions)			
Marketing, gathering and compression sales[a]	$2,085	$3,167	$3,760	$6,182
Gains on undesignated supply contract derivatives	220	—	220	—
Total marketing, gathering and compression sales	$2,305	$3,167	$3,980	$6,182

(a) Current Quarter and Current Period settlements of $27 million on supply contracts accounted for as derivatives are reflected in marketing, gathering and compression revenues.

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,	
	2015	2014	2015	2014
	($ in millions)			
Interest expense on senior notes	$171	$184	$342	$364
Interest expense on term loan	—	7	—	36
Amortization of loan discount, issuance costs and other	12	16	23	35
Interest expense on credit facilities	3	9	6	17
Gains on terminated fair value hedges	(1)	(1)	(2)	(2)
Gains on undesignated interest rate derivatives	—	(33)	(10)	(51)
Capitalized interest	(114)	(155)	(237)	(333)
Total interest expense	$71	$27	$122	$66

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

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,			
	2015		2014	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(216)	$(134)	$(247)	$(153)
Net change in fair value	—	—	1	—
(Gains) losses reclassified to income	5	3	3	(1)
Balance, end of period	$(211)	$(131)	$(243)	$(154)

	Six Months Ended June 30,			
	2015		2014	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(231)	$(143)	$(269)	$(167)
Net change in fair value	(2)	(1)	6	3
Losses reclassified to income	22	13	20	10
Balance, end of period	$(211)	$(131)	$(243)	$(154)

Approximately $123 million of the $131 million of accumulated other comprehensive loss as of June 30, 2015 represented 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. Deferred gain or loss amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of June 30, 2015, we expect to transfer approximately $20 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amounts will be transferred by December 31, 2022.

Credit Risk Considerations

Over-the-counter traded derivative instruments and our supply contracts 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, 2015, our oil, natural gas, interest rate and supply contract derivative instruments were spread among 17 counterparties.

Hedging Arrangements

As of June 30, 2015, our secured commodity hedging facility with 11 counterparties provided approximately 465 mmboe of hedging capacity for oil, natural gas and NGL price derivatives and 465 mmboe for basis derivatives with an aggregate mark-to-market capacity of $7.4 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 revolving credit facility and indentures. 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 Chesapeake exceed defined thresholds. As of June 30, 2015, we had hedged under the facility 40.5 mmboe of our future production with price derivatives and 2.3 mmboe with basis derivatives.

In April 2015, we also began entering into bilateral hedging agreements with the intention of replacing and terminating the respective counterparties' positions in the secured hedging facility. In the Current Quarter, we entered into bilateral arrangements that reduced the aggregate mark-to-market capacity under the secured hedging facility from $16.5 billion to $7.4 billion. The counterparties' obligations under the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts they owe Chesapeake exceed defined thresholds. As of June 30, 2015, we had hedged under bilateral agreements 84.2 mmboe of our future production with price derivatives and 15.6 mmboe with basis derivatives.

Fair Value

The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil and natural gas 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 oil, natural gas, 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.

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2015 and December 31, 2014:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of June 30, 2015				
Derivative Assets (Liabilities):				
Commodity assets	$—	$353	$73	$426
Commodity liabilities	—	(13)	(155)	(168)
Interest rate liabilities	—	—	—	—
Foreign currency liabilities	—	(88)	—	(88)
Supply contract assets	—	—	221	221
Total derivatives	$—	$252	$139	$391
As of December 31, 2014				
Derivative Assets (Liabilities):				
Commodity assets	$—	$784	$205	$989
Commodity liabilities	—	(9)	(259)	(268)
Interest rate liabilities	—	(17)	—	(17)
Foreign currency liabilities	—	(53)	—	(53)
Supply contract assets	—	—	1	1
Total derivatives	$—	$705	$(53)	$652

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(Unaudited)

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.

	Commodity Derivatives	Supply Contracts
	($ in millions)	
Beginning balance as of January 1, 2015	$(54)	$1
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	80	220
Total purchases, issuances, sales and settlements:		
Settlements	(108)	—
Ending balance as of June 30, 2015	$(82)	$221
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)	$—

(a)

	Oil, Natural Gas and NGL Sales		Marketing, Gathering and Compression Revenue	
	2015	2014	2015	2014
	($ in millions)			
Total gains (losses) included in earnings for the period	$80	$(173)	$220	$—
Change in unrealized gains (losses) related to assets still held at reporting date	$69	$(133)	$220	$—

(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.

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Qualitative and Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of oil and natural gas market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts. For example, an increase or decrease in the forward prices and volatility of oil and natural gas prices decreases or increases the fair value of oil and natural gas derivatives and adverse changes to our counterparties' creditworthiness decreases the fair value of our derivatives. The following table presents quantitative information about Level 3 inputs used in the fair value measurement of our commodity derivative contracts at fair value as of June 30, 2015:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value June 30, 2015 ($ in millions)	
Oil trades[(a)]	Oil price volatility curves	19.51% – 32.31%	26.97%	$(5	)
Supply contracts[(b)]	Oil price volatility curves	16.55% – 33.27%	20.05%	$221	
Natural gas trades[(a)]	Natural gas price volatility curves	20.47% – 56.46%	32.19%	$(77	)

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

(b) Fair value is based on an estimate derived from industry standard methodologies which consider historical relationships among various commodities, modeled market prices, time value and volatility factors.

9. Oil and Natural Gas Property Transactions

During 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 related to divestitures of noncore oil and natural gas properties. We had no material divestitures in the Current Period.

Under full cost accounting rules, we have accounted for the sale of oil and natural gas 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.

Joint Ventures

Between July 2008 and June 2013, we entered into eight significant joint ventures with other leading energy companies including Sinopec International Petroleum Exploration and Production (Sinopec), Total S.A. (Total), CNOOC Limited, Statoil, BP America and Freeport-McMoRan Inc. (formerly known as Plains Exploration & Production Company), pursuant to which we sold portions ranging from 20% to 50% of certain leasehold, producing properties and other assets located in eight different resource plays. In return, we received aggregate cash proceeds of $8.0 billion and commitments by our joint venture partners to pay, in the aggregate, 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. Each joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner and, if applicable, pays a specified percentage of our drilling and completion costs in designated wells. As of June 30, 2015, we had utilized all drilling carries from our joint venture partners.

During the Current Period and the Prior Period, our drilling and completion costs included the benefit of approximately $51 million and $357 million, respectively, in drilling and completion carries paid by our joint venture partners. All joint venture carries were fully utilized in the Current Period.

During the Current Period and the Prior Period, we sold interests in additional leasehold we acquired in the Marcellus, Barnett, Utica, Eagle Ford shales and Mid-Continent plays to our joint venture partners for approximately $19 million and $8 million, respectively.

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 oil and natural gas 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 novated hedges to each of the respective VPP buyers and these 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 these interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods these 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 the 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 oil and natural gas 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.

As of June 30, 2015, our outstanding VPPs consisted of the following:

				Volume Sold			
VPP #	Date of VPP	Location	Proceeds	Oil	Natural Gas	NGL	Total
			($ in millions)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
10	March 2012	Anadarko Basin Granite Wash	$744	3.0	87	9.2	160
9	May 2011	Mid-Continent	853	1.7	138	4.8	177
8	September 2010	Barnett Shale	1,150	—	390	—	390
4	December 2008	Anadarko and Arkoma Basins	412	0.5	95	—	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
			$5,481	5.2	1,105	14.0	1,220

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

	Three Months Ended June 30, 2015				Three Months Ended June 30, 2014			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10	78.0	2.2	268.7	4.3	103.0	2.7	329.9	5.3
9	42.5	3.5	94.9	4.4	47.5	3.9	103.9	4.8
8	—	13.6	—	13.6	—	15.2	—	15.2
6[(a)]	—	—	—	—	6.0	1.1	—	1.1
5[(a)]	—	—	—	—	6.0	1.7	—	1.7
4	10.7	2.0	—	2.1	12.2	2.3	—	2.3
3	—	1.6	—	1.6	—	1.8	—	1.8
2	—	1.0	—	1.0	—	1.6	—	1.6
1	—	3.3	—	3.3	—	3.4	—	3.4
	131.2	27.2	363.6	30.3	174.7	33.7	433.8	37.2

	Six Months Ended June 30, 2015				Six Months Ended June 30, 2014			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10	161.0	4.4	545.0	8.7	212.0	5.5	675.1	10.8
9	86.1	7.2	191.9	8.9	96.5	7.9	210.4	9.7
8	—	27.6	—	27.6	—	30.9	—	30.9
6[(a)]	—	—	—	—	12.0	2.2	—	2.3
5[(a)]	—	—	—	—	12.3	3.4	—	3.5
4	21.7	4.1	—	4.2	24.6	4.6	—	4.7
3	—	3.3	—	3.3	—	3.7	—	3.7
2	—	2.1	—	2.1	—	4.0	—	4.0
1	—	6.8	—	6.8	—	7.0	—	7.0
	268.8	55.5	736.9	61.6	357.4	69.2	885.5	76.6

(a) In 2014, we divested the properties associated with VPP #5 and VPP #6.

The volumes remaining to be delivered on behalf of our VPP buyers as of June 30, 2015 were as follows:

		Volume Remaining as of June 30, 2015			
VPP #	Term Remaining	Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
10	80	1.2	33.6	4.1	65.4
9	68	0.7	66.0	1.7	81.0
8	2	—	8.9	—	8.9
4	18	0.1	11.2	—	11.6
3	49	—	20.6	—	20.6
2	46	—	11.7	—	11.7

1	90	—	84.8	—	84.8
		2.0	236.8	5.8	284.0

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10. Investments

A summary of our investments, including our approximate ownership percentage and carrying value as of June 30, 2015 and December 31, 2014, is presented below.

	Accounting Method	Approximate Ownership % June 30, 2015	December 31, 2014	Carrying Value June 30, 2015	December 31, 2014
				($ in millions)	
FTS International, Inc.	Equity	30%	30%	$106	$116
Sundrop Fuels, Inc.	Equity	56%	56%	131	130
Other	—	—%	—%	18	19
Total investments				$255	$265

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company that, 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 $31 million, for our share of FTS' net loss and an accretion adjustment of $21 million related to the excess of our underlying equity in net assets of FTS over our carrying value.

As of June 30, 2015, the carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $23 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. During the Current Period, we recorded a $4 million charge related to our share of Sundrop's net loss and $5 million of capitalized interest associated with the construction of Sundrop's plant. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $83 million as of June 30, 2015 and will be amortized over the life of the plant once it is placed into service.

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 Prior 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.

Other. In the Prior 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.

11. 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 a 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, see Noncontrolling Interests in Note 6. 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, 2015, $1 million of cash and cash equivalents, $5 million of short-term derivative assets, $488 million of proved oil and natural gas properties, $361 million of accumulated depreciation, depletion and amortization and $11 million of other current 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 $10 million as of June 30, 2015.

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12. Other Property and Equipment

Net (Gains) Losses 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,	
	2015	2014	2015	2014
	($ in millions)			
Natural gas compressors	$—	$(94)	$—	$(120)
Gathering systems and treating plants	—	10	—	13
Oilfield services equipment	—	(9)	—	(7)
Buildings and land	—	1	1	1
Other	1	(1)	3	(2)
Total net (gains) losses on sales of fixed assets	$1	$(93)	$4	$(115)

In the Prior 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 Prior Period, we sold 102 compressors and related equipment to Access Midstream Partners, L.P. (ACMP) for proceeds of approximately $159 million. We recorded a $24 million gain associated with the transaction.

Assets Held for Sale

We are continuing to pursue the sale of miscellaneous properties located primarily in Oklahoma, West Virginia and the Fort Worth, Texas area. Land and buildings are recorded within our other 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, 2015. Oil and natural gas 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. As of June 30, 2015 and December 31, 2014, we had $93 million of buildings and land, net of accumulated depreciation, classified as assets held for sale on our condensed consolidated balance sheets.

13. Impairments

Impairments of Oil and Natural Gas Properties

Our oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. Estimated future net revenues for the quarterly ceiling limit are calculated using the average of commodity prices on the first day of the month over the trailing 12-month period. In the Current Quarter and the Current Period, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment in the carrying value of our oil and natural gas properties of $5.015 billion and $9.991 billion, respectively. Cash flow hedges as of June 30, 2015, which related to future periods, increased the ceiling test impairment by $190 million. Based on the first-day-of the-month prices we have received over the 11 months ended August 1, 2015, we expect to record another material write-down in the carrying value of our oil and natural gas properties in the third quarter of 2015. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

Impairments of Fixed Assets and Other

Compressors. In the Current Quarter, we recorded a $21 million impairment related to 466 compressors as a result of our pending sale of third-party rental compression assets in the Permian Basin and in western Oklahoma.

Contract Termination Charges. In the Current Quarter and the Current Period, as a result of reductions in our planned drilling activity in response to declines in oil and natural gas prices, we terminated contracts with drilling contractors and incurred charges of $3 million and $7 million, respectively. Further contract termination charges in subsequent quarters will occur if commodity prices remain low or continue to decline. The contract termination charges are included in our exploration and production operating segment.

Oilfield Services Equipment. In the Prior 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 are included in impairments of fixed assets and other in the condensed consolidated statement of operations. In addition, we recognized an impairment loss of approximately $15 million related to leasehold improvements associated with these assets. The drilling rigs and equipment are included in our former oilfield services operating segment.

Other. In the Current Quarter, we recorded a $47 million loss contingency related to contract disputes and a $13 million impairment of a note receivable as a result of the increased credit risk associated with declining commodity prices. In addition, under the terms of our joint venture agreements (see Note 9), 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 Prior 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 4 for additional discussion regarding our net acreage maintenance commitments.

Nonrecurring Fair Value Measurements. Fair value measurements for certain of the impairments discussed above were based on recent sales information for comparable assets. As the fair value was estimated using the market approach based on recent prices from orderly sales transactions for comparable assets between market participants, these values were classified as Level 2 in the fair value hierarchy. Other inputs used were not observable in the market; these values were classified as Level 3 in the fair value hierarchy.

14. 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 COO, into SSE, an independent, publicly traded company. 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 then-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 12 for further discussion of the sale.
- We transferred to a subsidiary of COO, at carrying value, certain of our buildings and land, most of which COO had been leasing from us prior to the spin-off.
- 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.

Following the spin-off, we have no ownership interest in SSE. Therefore, we ceased to consolidate SSE's assets and liabilities as of the spin-off date. Because we expect to have significant continued involvement associated with SSE's future operations through the various agreements we entered into in connection with the spin-off, 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. For segment disclosures, we have labeled our oilfield services segment as "former oilfield services". See Note 17 for additional information regarding our segments.

In the Prior Period, our stockholders' equity decreased by $268 million, net of $152 million of associated deferred tax liabilities, as the result of the spin-off, and we recognized $12 million of charges associated with the spin-off that are included in restructuring and other termination costs on our consolidated statement of operations.

15. Income Taxes

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry.

Based on the expected material write-downs of the carrying value of our oil and natural gas properties and our operating results in subsequent quarters, we project being in a net deferred tax asset position at December 31, 2015. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the three-year period ending December 31, 2015. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

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.

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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, 2015 and December 31, 2014:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of June 30, 2015				
Financial Assets (Liabilities):				
Other current assets	$62	$—	$—	$62
Other current liabilities	(63)	—	—	(63)
Total	$(1)	$—	$—	$(1)
As of December 31, 2014				
Financial Assets (Liabilities):				
Other current assets	$57	$—	$—	$57
Other current liabilities	(58)	—	—	(58)
Total	$(1)	$—	$—	$(1)

See Note 3 for information regarding fair value of other financial instruments. See Note 8 for information regarding fair value measurement of derivatives.

Nonrecurring Fair Value Measurements

See Note 13 regarding nonrecurring fair value measurements.

17. Segment Information

As of June 30, 2015, 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 oil, natural gas and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of oil, natural gas and NGL. In addition, prior to the spin-off of our oilfield services business in June 2014, 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 table below.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of oil, natural gas and NGL related to Chesapeake's ownership interests by our marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. These amounts totaled $1.204 billion, $2.188 billion, $2.437 billion and $4.596 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 and $544 million for the Prior Quarter 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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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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, 2015						
Revenues	$699	$3,509	$—	$—	$(1,175)	$3,033
Intersegment revenues	29	(1,204)	—	—	1,175	—
Total revenues	$728	$2,305	$—	$—	$—	$3,033
Income (Loss) Before Income Taxes	$(5,785)	$134	$—	$(31)	$86	$(5,596)
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
Six Months Ended June 30, 2015						
Revenues	$1,761	$6,417	$—	$—	$(2,385)	$5,793
Intersegment revenues	52	(2,437)	—	—	2,385	—
Total revenues	$1,813	$3,980	$—	$—	$—	$5,793
Income (Loss) Before Income Taxes	$(11,134)	$138	$—	$(45)	$353	$(10,688)
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

As of

June 30, 2015						
Total Assets	$22,815	$1,946	$—	$4,364	$(527)	$28,598
As of December 31, 2014						
Total Assets	$35,381	$1,978	$—	$4,283	$(891)	$40,751

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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 3 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 former oilfield services subsidiaries were separately capitalized and were not guarantors of our debt obligations.

The tables 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, 2015 and December 31, 2014 and for the three and six months ended June 30, 2015 and 2014. This 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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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF JUNE 30, 2015
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$2,148	$1	$ 30	$(128)	$2,051
Restricted cash	—	—	38	—	38
Other	78	2,013	51	—	2,142
Intercompany receivable, net	24,917	—	365	(25,282)	—
Total Current Assets	27,143	2,014	484	(25,410)	4,231
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties, at cost based on full cost accounting, net	—	19,478	716	1,090	21,284
Other property and equipment, net	—	2,237	1	—	2,238
Property and equipment held for sale, net	—	93	—	—	93
Total Property and Equipment, Net	—	21,808	717	1,090	23,615
LONG-TERM ASSETS:					
Other assets	121	614	27	(10)	752
Investments in subsidiaries and intercompany advances	(5,967)	188	—	5,779	—
TOTAL ASSETS	$21,297	$24,624	$ 1,228	$(18,551)	$28,598
CURRENT LIABILITIES:					
Current liabilities	$1,547	$3,653	$ 56	$(128)	$5,128
Intercompany payable, net	—	24,785	—	(24,785)	—
Total Current Liabilities	1,547	28,438	56	(24,913)	5,128
LONG-TERM LIABILITIES:					
Long-term debt, net	10,655	—	—	—	10,655
Deferred income tax liabilities	—	1,263	78	67	1,408
Other long-term liabilities	137	890	137	—	1,164
Total Long-Term Liabilities	10,792	2,153	215	67	13,227
EQUITY:					
Chesapeake stockholders' equity	8,958	(5,967)	957	5,010	8,958
Noncontrolling interests	—	—	—	1,285	1,285
Total Equity	8,958	(5,967)	957	6,295	10,243
TOTAL LIABILITIES AND EQUITY	$21,297	$24,624	$ 1,228	$(18,551)	$28,598

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

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$4,100	$2	$ 84	$(78)	$4,108
Restricted cash	—	—	38	—	38
Other	55	3,174	93	—	3,322
Intercompany receivable, net	24,527	—	341	(24,868)	—
Total Current Assets	28,682	3,176	556	(24,946)	7,468
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties, at cost based on full cost accounting, net	—	28,358	1,112	673	30,143
Other property and equipment, net	—	2,276	3	—	2,279
Property and equipment held for sale, net	—	93	—	—	93
Total Property and Equipment, Net	—	30,727	1,115	673	32,515
LONG-TERM ASSETS:					
Other assets	153	618	26	(29)	768
Investments in subsidiaries and intercompany advances	126	467	—	(593)	—
TOTAL ASSETS	$28,961	$34,988	$ 1,697	$(24,895)	$40,751
CURRENT LIABILITIES:					
Current liabilities	$792	$5,081	$ 68	$(78)	$5,863
Intercompany payable, net	—	24,940	—	(24,940)	—
Total Current Liabilities	792	30,021	68	(25,018)	5,863
LONG-TERM LIABILITIES:					
Long-term debt, net	11,154	—	—	—	11,154
Deferred income tax liabilities	—	3,751	234	200	4,185
Other long-term liabilities	112	1,090	142	—	1,344
Total Long-Term Liabilities	11,266	4,841	376	200	16,683
EQUITY:					
Chesapeake stockholders' equity	16,903	126	1,253	(1,379)	16,903
Noncontrolling interests	—	—	—	1,302	1,302
Total Equity	16,903	126	1,253	(77)	18,205
TOTAL LIABILITIES AND EQUITY	$28,961	$34,988	$ 1,697	$(24,895)	$40,751

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

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED JUNE 30, 2015
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$—	$693	$35	$—	$728
Marketing, gathering and compression	—	2,305	—	—	2,305
Total Revenues	—	2,998	35	—	3,033
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	267	9	—	276
Production taxes	—	33	1	—	34
Marketing, gathering and compression	—	2,096	—	—	2,096
General and administrative	—	67	2	—	69
Restructuring and other termination costs	—	(4)	—	—	(4)
Provision for legal contingencies	339	(5)	—	—	334
Oil, natural gas and NGL depreciation, depletion and amortization	—	586	23	(8)	601
Depreciation and amortization of other assets	—	34	—	—	34
Impairment of oil and natural gas properties	—	5,012	186	(183)	5,015
Impairments of fixed assets and other	—	84	—	—	84
Net losses on sales of fixed assets	—	1	—	—	1
Total Operating Expenses	339	8,171	221	(191)	8,540
LOSS FROM OPERATIONS	(339)	(5,173)	(186)	191	(5,507)
OTHER INCOME (EXPENSE):					
Interest expense	(180)	(37)	—	146	(71)
Losses on investments	—	(17)	—	—	(17)
Other income (expense)	81	(7)	—	(75)	(1)
Equity in net earnings (losses) of subsidiary	(3,792)	(154)	—	3,946	—
Total Other Expense	(3,891)	(215)	—	4,017	(89)
LOSS BEFORE INCOME TAXES	(4,230)	(5,388)	(186)	4,208	(5,596)
INCOME TAX BENEFIT	(122)	(1,404)	(50)	70	(1,506)
NET LOSS	(4,108)	(3,984)	(136)	4,138	(4,090)
Net income attributable to noncontrolling interests	—	—	—	(18)	(18)
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	(4,108)	(3,984)	(136)	4,120	(4,108)
Other comprehensive income	—	3	—	—	3
COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE	$(4,108)	$(3,981)	$(136)	$4,120	$(4,105)

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$—	$1,618	$88	$(2)	$1,704
Marketing, gathering and compression	—	3,166	1	—	3,167
Oilfield services	—	23	499	(241)	281
Total Revenues	—	4,807	588	(243)	5,152
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	272	10	—	282
Production taxes	—	70	2	—	72
Marketing, gathering and compression	—	3,166	—	—	3,166
Oilfield services	—	22	375	(185)	212
General and administrative	—	68	22	—	90
Restructuring and other termination costs	—	30	3	—	33
Oil, natural gas and NGL depreciation, depletion and amortization	—	615	36	10	661
Depreciation and amortization of other assets	—	38	71	(30)	79
Impairment of oil and natural gas properties	—	—	38	(38)	—
Impairments of fixed assets and other	—	37	3	—	40
Net losses on sales of fixed assets	—	(85)	(8)	—	(93)
Total Operating Expenses	—	4,233	552	(243)	4,542
INCOME FROM OPERATIONS	—	574	36	—	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	136	29	—	(158)	7
Equity in net earnings (losses) of subsidiary	324	(32)	—	(292)	—
Total Other Income (Expense)	109	(25)	(25)	(298)	(239)
INCOME BEFORE INCOME TAXES	109	549	11	(298)	371
INCOME TAX EXPENSE (BENEFIT)	(82)	221	4	(2)	141
NET INCOME	191	328	7	(296)	230
Net income attributable to noncontrolling interests	—	—	—	(39)	(39)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	191	328	7	(335)	191

Other comprehensive income (loss)	1	(2)	—	—	(1)
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$192	$326	$7	$(335)	$190

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2015
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$—	$1,729	$84	$—	$1,813
Marketing, gathering and compression	—	3,980	—	—	3,980
Total Revenues	—	5,709	84	—	5,793
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	554	21	—	575
Production taxes	—	60	2	—	62
Marketing, gathering and compression	—	3,796	—	—	3,796
General and administrative	1	121	3	—	125
Restructuring and other termination costs	—	(14)	—	—	(14)
Provision for legal contingencies	339	20	—	—	359
Oil, natural gas and NGL depreciation, depletion and amortization	—	1,249	55	(19)	1,285
Depreciation and amortization of other assets	—	69	—	—	69
Impairment of oil and natural gas properties	—	9,983	406	(398)	9,991
Impairments of fixed assets and other	—	88	—	—	88
Net losses on sales of fixed assets	—	4	—	—	4
Total Operating Expenses	340	15,930	487	(417)	16,340
LOSS FROM OPERATIONS	(340)	(10,221)	(403)	417	(10,547)
OTHER INCOME (EXPENSE):					
Interest expense	(351)	(74)	—	303	(122)
Losses on investments	—	(24)	—	—	(24)
Other income (expense)	(39)	7	—	37	5
Equity in net earnings (losses) of subsidiary	(7,314)	(333)	—	7,647	—
Total Other Expense	(7,704)	(424)	—	7,987	(141)
LOSS BEFORE INCOME TAXES	(8,044)	(10,645)	(403)	8,404	(10,688)
INCOME TAX BENEFIT	(197)	(2,778)	(107)	204	(2,878)
NET LOSS	(7,847)	(7,867)	(296)	8,200	(7,810)
Net income attributable to noncontrolling interests	—	—	—	(37)	(37)
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	(7,847)	(7,867)	(296)	8,163	(7,847)
Other comprehensive income (loss)	(2)	14	—	—	12
COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE	$(7,849)	$(7,853)	$(296)	$8,163	$(7,835)

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SIX MONTHS ENDED JUNE 30, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$—	$3,282	$192	$(3)	$3,471
Marketing, gathering and compression	—	6,180	2	—	6,182
Oilfield services	—	40	983	(478)	545
Total Revenues	—	9,502	1,177	(481)	10,198
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	549	21	—	570
Production taxes	—	119	3	—	122
Marketing, gathering and compression	—	6,145	2	—	6,147
Oilfield services	—	54	769	(392)	431
General and administrative	—	124	45	—	169
Restructuring and other termination costs	—	23	3	—	26
Oil, natural gas and NGL depreciation, depletion and amortization	—	1,201	79	8	1,288
Depreciation and amortization of other assets	—	78	143	(64)	157
Impairment of oil and natural gas 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	—	8,221	1,180	(546)	8,855
INCOME (LOSS) FROM OPERATIONS	—	1,281	(3)	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 (expense)	479	(114)	1	(353)	13
Equity in net earnings (losses) of subsidiary	655	(111)	—	(544)	—
Total Other Income (Expense)	592	(203)	(46)	(569)	(226)
INCOME (LOSS) BEFORE INCOME TAXES	592	1,078	(49)	(504)	1,117
INCOME TAX EXPENSE (BENEFIT)	(24)	448	(18)	15	421
NET INCOME (LOSS)	616	630	(31)	(519)	696
Net income attributable to noncontrolling interests	—	—	—	(80)	(80)

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	616	630	(31)	(599)	616
Other comprehensive income	3	5	—	—	8
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$619	$635	$(31)	$(599)	$624

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CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
SIX MONTHS ENDED JUNE 30, 2015
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$—	$638	$99	$—	$737
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(2,077)	(91)	—	(2,168)
Acquisitions of proved and unproved properties	—	(266)	—	—	(266)
Proceeds from divestitures of proved and unproved properties	—	14	—	—	14
Additions to other property and equipment	—	(93)	—	—	(93)
Other investing activities	—	(2)	3	—	1
Net Cash Used In Investing Activities	—	(2,424)	(88)	—	(2,512)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Other financing activities	(565)	398	(65)	(50)	(282)
Intercompany advances, net	(1,387)	1,387	—	—	—
Net Cash Used In Financing Activities	(1,952)	1,785	(65)	(50)	(282)
Net decrease in cash and cash equivalents	(1,952)	(1)	(54)	(50)	(2,057)
Cash and cash equivalents, beginning of period	4,100	2	84	(78)	4,108
Cash and cash equivalents, end of period	$2,148	$1	$30	$(128)	$2,051

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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:					
Net Cash Provided By Operating Activities	$—	$2,337	$306	$—	$2,643
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(1,946)	(50)	—	(1,996)
Acquisitions of proved and unproved properties	—	(354)	(2)	—	(356)
Proceeds from divestitures of proved and unproved properties	—	247	1	—	248
Additions to other property and equipment	—	(368)	(252)	—	(620)
Other investing activities	—	877	60	7	944
Net Cash Used In Investing Activities	—	(1,544)	(243)	7	(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)	(29)	(94)	(32)	(348)
Intercompany advances, net	1,186	(764)	(422)	—	—
Net Cash Provided By (Used In) Financing Activities	597	(793)	(10)	(32)	(238)
Net increase in cash and cash equivalents	597	—	53	(25)	625
Cash and cash equivalents, beginning of period	799	—	38	—	837
Cash and cash equivalents, end of period	$1,396	$—	$91	$(25)	$1,462

19. Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (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 fiscal years, and interim periods within those years, beginning after December 15, 2016, with early application not permitted. In July 2015, the FASB approved a one-year deferral of the effective date as well as permission to early adopt the new revenue recognition standard as of the original effective date. We are evaluating the impact on our condensed consolidated financial statements.

In April 2015, the FASB issued an accounting standards update on the presentation of debt issuance costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs is not affected by the update. For public entities, the guidance is effective for reporting periods beginning after December 15, 2015, and it is not expected to have a material impact on our condensed consolidated financial statements.

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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, oil, natural gas and NGL sales, average sales prices received, and other operating income and expenses for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Production:				
Oil (mmbbl)	10.8	10.3	21.8	20.2
Natural gas (bcf)	275.4	271.3	539.2	531.4
NGL (mmbbl)	7.2	7.7	14.0	15.2
Oil equivalent (mmboe)[a]	63.9	63.2	125.7	124.0
Oil, Natural Gas and NGL Sales ($ in millions):				
Oil sales	$557	$1,006	$1,008	$1,928
Oil derivatives – realized gains (losses)[b]	182	(127)	417	(210)
Oil derivatives – unrealized gains (losses)[b]	(234)	(113)	(344)	(103)
Total oil sales	505	766	1,081	1,615
Natural gas sales	206	750	631	1,754
Natural gas derivatives – realized gains (losses)[b]	71	(86)	271	(240)
Natural gas derivatives – unrealized gains (losses)[b]	(67)	113	(231)	(41)
Total natural gas sales	210	777	671	1,473
NGL sales	13	161	61	383
Total NGL sales	13	161	61	383
Total oil, natural gas and NGL sales	$728	$1,704	$1,813	$3,471
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$51.21	$97.49	$46.16	$95.59
Natural gas ($ per mcf)	$0.75	$2.76	$1.17	$3.30
NGL ($ per bbl)	$1.90	$21.03	$4.37	$25.10
Oil equivalent ($ per boe)	$12.13	$30.32	$13.52	$32.79
Average Sales Price (including realized gains (losses) on derivatives):				
Oil ($ per bbl)	$67.91	$85.23	$65.22	$85.16
Natural gas ($ per mcf)	$1.01	$2.45	$1.67	$2.85
NGL ($ per bbl)	$1.90	$21.03	$4.37	$25.10
Oil equivalent ($ per boe)	$16.08	$26.97	$18.99	$29.16

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Other Operating Income[c] ($ in millions):				
Marketing, gathering and compression net margin[d]	$209	$1	$184	$35
Oilfield services net margin	$—	$69	$—	$114
Expenses ($ per boe):				
Oil, natural gas and NGL production	$4.32	$4.46	$4.58	$4.59
Production taxes	$0.52	$1.14	$0.49	$0.99
General and administrative[e]	$1.08	$1.43	$1.00	$1.37
Oil, natural gas and NGL depreciation, depletion and amortization	$9.39	$10.45	$10.22	$10.39
Depreciation and amortization of other assets	$0.52	$1.25	$0.55	$1.27
Interest expense[f]	$1.12	$0.92	$1.05	$0.91
Interest Expense ($ in millions):				
Interest expense	$72	$61	$134	$119
Interest rate derivatives – realized (gains) losses[g]	(1)	(3)	(2)	(6)
Interest rate derivatives – unrealized (gains) losses[g]	—	(31)	(10)	(47)
Total interest expense	$71	$27	$122	$66

(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.

(b) Realized gains (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 (losses) related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains (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 (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) The Current Quarter and the Current Period include supply contract settlements of $27 million. The Current Quarter and the Current Period include unrealized gains of $220 million on the fair value of our supply contract derivatives. See Note 8 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.

(e) Includes share-based compensation but excludes restructuring and other termination costs.

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

(g) 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.

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Overview

Chesapeake is currently the second-largest producer of natural gas and the 11th largest producer of oil and natural gas liquids (NGL) in the United States. We own interests in approximately 44,900 oil and natural gas wells and produced an average of approximately 703 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, Cleveland, Tonkawa and Mississippian Lime plays in the Anadarko Basin in northwestern Oklahoma and the Texas Panhandle; and the Niobrara Shale and Upper Cretaceous sands in the Powder River Basin in Wyoming. Our natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin in Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. We also own oil and natural gas marketing and natural gas gathering 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 four fundamental tenets: financial discipline, profitable and efficient growth from captured resources, exploration and business development.

We are applying financial discipline to all aspects of our business with the primary goal of continuing to increase financial and operational flexibility through value-driven spending and lower business costs. In addition, we will continue to strive towards balancing capital expenditures with cash flows and achieving investment grade metrics. As a result of our focus on financial discipline, our combined production and general and administrative expenses decreased to $5.40 per boe in the Current Quarter compared to $5.89 per boe in the Prior Quarter and to $5.58 per boe in the Current Period compared to $5.96 per boe in the Prior Period. As part of a broader disciplined approach to decrease our financial complexity and increase our liquidity, we recently announced that we have eliminated quarterly dividends on our common stock and have entered into agreements to eliminate future preferred share dividends and drilling and overriding royalty interest commitments in our CHK Cleveland Tonkawa subsidiary. See Recent Developments below.

Our substantial inventory of hydrocarbon resources, including our undeveloped acreage inventory, provides a strong foundation for future growth. 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. In addition, through operational improvements, we are experiencing increased well productivity from larger completions and lower production declines. We are also evaluating additional asset sales, joint ventures and farmouts to increase our liquidity and future cash flow. We 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 strategy.

Although our substantial inventory of hydrocarbon resources provides a strong foundation, we believe exploration and business development are also key opportunities for future growth. We believe we will have opportunities to enhance or expand our portfolio through leveraging our innovative technology and expertise, exploring and exploiting new domestic resources, pursuing international growth opportunities and targeting strategic acquisitions. We believe these platforms will increase shareholder returns in the future.

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Operating Results

Our Current Quarter production of 64 mmboe consisted of 11 mmbbls of oil (17% on an oil equivalent basis), 275 bcf of natural gas (72% on an oil equivalent basis), and 7 mmbbls of NGL (11% on an oil equivalent basis). Liquids represented 28% of total production for both the Current Quarter and the Prior Quarter. Our daily production for the Current Quarter averaged approximately 703 mboe, an increase of 1% from the Prior Quarter. Compared to the Prior Quarter, average daily oil production increased by 5%, or approximately 6 mbbls per day; average daily natural gas production increased by 2%, or approximately 45 mmcf per day; and average daily NGL production decreased by 6%, or approximately 5 mbbls per day. Our NGL production decreased and our natural gas production remained relatively flat as a result of the sale of certain of our southern Marcellus Shale and Utica Shale assets in December 2014. Adjusted for asset sales, our total daily production increased 13% in the Current Quarter compared to the Prior Quarter. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $1.141 billion to $776 million in the Current Quarter compared to $1.917 billion in the Prior Quarter, primarily due to significant decreases in the prices received for oil, natural gas and NGL sold. See Results of Operations below for additional details.

Our Current Period production of 126 mmboe consisted of 22 mmbbls of oil (18% on an oil equivalent basis), 539 bcf of natural gas (71% on an oil equivalent basis), and 14 million mmbbls of NGL (11% on an oil equivalent basis). Liquids represented 29% of total production for the Current Period, up from 28% in the Prior Period. Our daily production for the Current Period averaged approximately 695 mboe, an increase of 1% from the Prior Period. Compared to the Prior Period, average daily oil production increased by 8%, or approximately 9 mbbls per day; average daily natural gas production increased by 1%, or approximately 43 mmcf per day; and average daily NGL production decreased by 8% or approximately 7 mbbls per day. Our NGL production decreased and our natural gas production remained relatively flat as a result of the sale of certain of our southern Marcellus Shale and Utica Shale assets in December 2014. Adjusted for asset sales, our total daily production increased 13% in the Current Period compared to the Prior Period. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $2.365 billion to $1.700 billion in the Current Period compared to $4.065 billion in the Prior Period, primarily due to significant decreases in the prices received for oil, natural gas and NGL sold. See Results of Operations below for additional details.

Capital Expenditures

Our drilling and completion capital expenditures during the Current Quarter were approximately $787 million and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $56 million, for a total of approximately $843 million. In the Current Quarter, we operated an average of 26 rigs, a decrease of 36 rigs compared to the Prior Quarter. As a result of lower drilling and completion activity, partially offset by a reduction in drilling carries received from our joint venture partners, drilling and completion expenditures decreased approximately $344 million in the Current Quarter compared to the Prior Quarter. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $210 million, or 79%, compared to the Prior Quarter. The reduction is primarily the result of the elimination of capital expenditures for our former oilfield services business which was spun off in June 2014.

Our capitalized interest was approximately $114 million and $155 million in the Current Quarter and the Prior Quarter, respectively. Including capitalized interest, total capital investments were approximately $957 million in the Current Quarter compared to $1.6 billion for the Prior Quarter.

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Our drilling and completion capital expenditures during the Current Period were approximately $2.1 billion and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $119 million, for a total of approximately $2.2 billion. In the Current Period, we operated an average of 40 rigs, a decrease of 25 rigs compared to the Prior Period. Although our average operated rig count decreased in the Current Period compared to the Prior Period, our drilling and completion expenditures increased approximately $227 million as a result of a decrease in drilling and completion carries received from our joint venture partners and significant well completion costs incurred in the Current Period for wells that had been drilled, but not completed, in prior periods. In addition, completion costs increased as a result of longer laterals drilled and more frac stages per well being completed. We expect that drilling and completion costs for the remainder of 2015 will be significantly lower than those incurred in the Current Period. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $609 million, or 84%, compared to the Prior Period. The reduction is primarily the result of the elimination of capital expenditures for our former oilfield services business which was spun off in June 2014. In the Prior 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 our oilfield services business in June 2014.

Our capitalized interest was approximately $237 million and $333 million in the Current Period and the Prior Period, respectively. Including capitalized interest, total capital investments were approximately $2.4 billion in the Current Period compared to $2.9 billion for the Prior Period.

Based on planned activity levels for the remainder of 2015, we project that full-year 2015 capital expenditures for drilling and completion, leasehold, geological and geophysical and other property and equipment will be $3.5 billion to $4.0 billion, inclusive of capitalized interest. The decrease from the $6.7 billion spent in 2014 is primarily driven by reduced activity as a result of substantially lower oil and natural gas prices forecasted in 2015 compared to 2014. See Liquidity and Capital Resources for additional information on how we plan to fund our capital budget.

Recent Developments

Cleveland Tonkawa Transactions

On June 30, 2015, we entered into an agreement to sell all of the properties held by CHK Cleveland Tonkawa, L.L.C. (CHK C-T) to FourPoint Energy, LLC (FourPoint) for approximately $575 million. See Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a description of CHK C-T. We will use the consideration from the sale of the CHK C-T properties and cash held by CHK C-T to repurchase the outstanding preferred shares in CHK C-T, subject to customary adjustments to the purchase price and certain indemnity obligations in connection with the sale for which Chesapeake is responsible. Upon closing of the transaction, which we expect to occur in the 2015 third quarter, we will eliminate the noncontrolling interest and overriding royalty interest (ORRI) obligation on our condensed consolidated balance sheet, approximately $75 million in annual preferred dividend payments and all related future drilling and ORRI commitments attributable to CHK-C-T. Also on June 30, 2015, in a related transaction, we agreed to sell to FourPoint for approximately $90 million noncore properties adjacent to the CHK C-T properties. Chesapeake's net production from the assets being sold in the two transactions was approximately 15 mboe per day in the Current Quarter. Separately, certain of CHK C-T's investors and their affiliates agreed to sell to FourPoint their ORRIs in the CHK C-T properties for approximately $175 million. The closing of each of the three transactions is dependent on the closing of each of the other two transactions.

Compression Restructuring

We plan to fully integrate our two wholly owned compression subsidiaries, MidCon Compression, L.L.C. and Compass Manufacturing, L.L.C., into our wholly owned operating subsidiary, Chesapeake Operating, L.L.C., by the end of 2015. We believe this integration will improve our operational performance as we increase efficiencies and optimize processes and personnel. In addition, in July 2015, we entered into agreements to sell third-party rental compressors, and we ultimately plan to divest all of our third-party compressor rental business.

Elimination of Common Stock Dividend

On July 21, 2015, we announced that we have eliminated our annual common stock dividend of $0.35 per share. The elimination of the common stock dividend will allow us to retain approximately $240 million annually. We plan to redirect the cash into our future capital programs to maximize the returns available to our shareholders.

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Liquidity and Capital Resources

Liquidity Overview

Based on budgeted capital expenditures, our forecasted operating cash flow and projected levels of indebtedness, we believe we have sufficient liquidity to fund our current and long-term operations, including our contractual commitments to third parties pursuant to various agreements described in Contractual Obligations and Off-Balance Sheet Arrangements below.

As of June 30, 2015, we had approximately $6.036 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving credit facility) compared to $8.093 billion as of December 31, 2014, and we had a working capital deficit of approximately $897 million compared to working capital of approximately $1.605 billion as of December 31, 2014. The decrease in cash availability and working capital from December 31, 2014 to June 30, 2015 is primarily the result of the excess of our capital expenditures in the Current Period over our operating cash flow due to lower oil, natural gas and NGL prices received for our production in the Current Period. Additionally, the decrease in working capital is the result of the reclassification of our 3.25% Senior Notes due 2016 from a long-term liability to a current liability as of March 31, 2015 and accruals related to certain of our legal matters.

As a result of substantially lower oil and natural gas prices in 2015 compared to 2014, we plan to operate an average of 25 to 35 rigs in 2015, a decrease from an average of 65 rigs in 2014, and our lowest operated rig activity level since 2004. With this level of activity, 2015 commodity prices and our current derivative contracts in place, we expect to fund a portion of our planned capital expenditures with cash on hand, and we did so in the Current Period. We currently have downside price protection on approximately 48% of our projected remaining 2015 oil production at an average price of $87.64 per bbl, of which 11% is hedged under three-way collar arrangements based on an average bought put NYMEX price of $90.00 per bbl and exposure below an average sold put NYMEX price of $80.00 per bbl. We also have downside price protection on approximately 39% of our projected remaining 2015 natural gas production at an average price of $3.87 per mcf, of which 14% is hedged under three-way collar arrangements based on an average bought put NYMEX price of $4.17 per mcf and exposure below an average sold put NYMEX price of $3.38 per mcf.

Management continues to review operational plans for the 2015 second half and beyond, which could result in changes to projected capital expenditures and revenues from sales of oil, natural gas and NGL. We closely monitor the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our revolving credit facility. We believe we have adequate flexibility to respond to negative developments if needed; however, adjustments in discretionary capital expenditures could negatively impact our ability to meet certain of our drilling and midstream commitments. Our current budget anticipates having sufficient cash on hand to remain undrawn on our revolving credit facility through December 31, 2015.

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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 9, 10 and 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of divestitures of oil and natural gas assets, investments and other assets, respectively.

	Six Months Ended June 30,	
	2015	2014
	($ in millions)	
Cash Provided by Operating Activities	$737	$2,643
Divestitures of Oil and Natural Gas Assets:		
Joint venture leasehold	19	8
Other oil and natural gas properties[a]	(5)	240
Total divestitures of oil and natural gas assets	14	248
Sales of Other Assets:		
Compressors sold to ACMP	—	159
Compressors sold to Exterran	—	362
Other property and equipment	7	192
Total sales of other assets	7	713
Other Sources of Cash and Cash Equivalents:		
Proceeds from sales of investments	—	239
Proceeds from long-term debt, net	—	2,966
Proceeds from oilfield services long-term debt, net	—	888
Total other sources of cash and cash equivalents	—	4,093
Total sources of cash and cash equivalents	$758	$7,697

(a) Primarily includes post-closing costs on divestitures closed in prior periods.

Cash provided by operating activities was $737 million in the Current Period compared to $2.643 billion in the Prior Period. The decrease in cash provided by operating activities from the Current Period to the Prior Period is primarily the result of lower realized prices for the oil, natural gas and NGL we sold, partially offset by realized gains on our derivative instruments and decreases in certain of our operating expenses. 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, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under Results of Operations.

We currently plan to use cash and cash equivalents on hand to fund a portion of our operating activities and capital expenditures in 2015 as needed. Our $4.0 billion unsecured revolving credit facility also provides an additional source of liquidity. Prior to June 2014, we also utilized a $500 million oilfield services credit facility. This facility was terminated in June 2014 in connection with the spin-off of our oilfield services business. We had no borrowings or repayments in the Current Period, and borrowed $857 million and repaid $1.239 billion in the Prior Period under our revolving credit facilities. As of June 30, 2015, we had no outstanding borrowings under our revolving credit facility and had utilized approximately $15 million of the facility for various letters of credit. Our revolving credit facility is unsecured and not subject to a borrowing base; however, we will be required to provide collateral and the facility will be subject to a borrowing base if our credit rating declines to specified levels.

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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,	
	2015	2014
	($ in millions)	
Oil and Natural Gas Expenditures:		
Drilling and completion costs[(a)]	$2,150	$1,967
Acquisitions of proved and unproved properties	54	59
Interest capitalized on unproved properties	230	326
Total oil and natural gas expenditures	2,434	2,352
Other Uses of Cash and Cash Equivalents:		
Cash paid to repurchase debt	—	3,362
Cash paid to purchase leased rigs and compressors	—	422
Payments on credit facility borrowings, net	—	382
Additions to other property and equipment	93	153
Dividends paid	204	203
Distributions to noncontrolling interest owners	57	105
Cash paid for oilfield service equipment deposits	—	45
Cash paid for financing derivatives[(b)]	—	32
Additions to investments	6	5
Other	21	11
Total other uses of cash and cash equivalents	381	4,720
Total uses of cash and cash equivalents	$2,815	$7,072

(a) Net of $51 million and $357 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 oil and natural gas properties. During the Current Period, our average operated rig count was 40 rigs compared to an average operated rig count of 65 rigs in the Prior Period. Although our average operated rig count decreased in the Current Period compared to the Prior Period, our drilling and completion expenditures increased as a result of a decrease in drilling and completion carries received from our joint venture partners and significant well completion costs incurred in the Current Period for wells that had been drilled, but not completed, in prior periods. In addition, completion costs increased as a result of longer laterals drilled and more frac stages per well being completed.

Capital expenditures related to our midstream, oilfield services and other fixed assets were $93 million in the Current Period compared to $153 million in the Prior Period. The reduction of these expenditures in the Current Period as compared to the Prior Period is primarily the result of the spin-off of our oilfield services business in June 2014 and reductions in construction expenditures on our corporate headquarters and field offices.

In the Prior Period, we 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 our oilfield services business in June 2014. In addition, in the Prior Period, 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 $118 million and $117 million in the Current Period and the Prior Period, respectively. We paid dividends on our preferred stock of $86 million in both the Current Period and the Prior Period. We have eliminated common stock dividends effective with the 2015 third quarter. See Recent Developments above.

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Revolving Credit Facility

We have a $4.0 billion senior unsecured revolving credit facility that matures in December 2019. As of June 30, 2015, we had no outstanding borrowings under the facility and utilized $15 million of the facility for various letters of credit. Borrowings under the facility bear interest at a variable rate. The applicable interest rates under the facility fluctuate based on our credit ratings. We would be required to post collateral in the event of a downgrade of our credit ratings to specified levels. The financial covenants require us to maintain, as of the last day of each fiscal quarter, (i) a net debt to capitalization ratio (as defined in the credit agreement) that does not exceed 0.65 to 1.0, and (ii) a leverage ratio (net debt to consolidated EBITDA, as defined in the credit agreement) that does not exceed 4.0 to 1.0; provided, however, that the leverage ratio will not apply during any period in which our credit ratings, as determined by either Moody's Investors Services, Inc. or Standard & Poor's Ratings Services, meet and continue to meet certain investment grade thresholds, as defined in the credit agreement. As of June 30, 2015, our net debt to capitalization ratio was approximately 0.37 to 1.0, and our leverage ratio was approximately 2.72 to 1.0. We were in compliance with all financial covenants under the credit agreement as of June 30, 2015. See Note 3 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 the credit facility.

Hedging Arrangements

We have a multi-counterparty secured hedging facility with 11 counterparties that have committed to provide approximately 465 mmboe of hedging capacity for oil, natural gas and NGL price derivatives and 465 mmboe for basis derivatives with an aggregate mark-to-market capacity of $7.4 billion as of June 30, 2015. In April 2015, we also began using bilateral hedging agreements. For further discussion of the terms of the hedging facility and bilateral hedging agreements, see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

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Senior Note Obligations

Our senior note obligations consisted of the following as of June 30, 2015:

	June 30, 2015
	($ in millions)
3.25% senior notes due 2016	$500
6.25% euro-denominated senior notes due 2017[(a)]	384
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)]	(188)
Interest rate derivatives[(d)]	8
Total senior notes, net	11,544
Less current maturities of long-term debt, net[(e)]	(889)
Total long-term senior notes, net	$10,655

(a) The principal amount shown is based on the exchange rate of $1.1147 to €1.00 as of June 30, 2015. See Note 8 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 first put date, for the 2.75% Contingent Convertible Senior Notes due 2035, is November 15, 2015. 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 as of June 30, 2015 was $181 million associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(d) See Note 8 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.

(e) Current maturities of long-term debt, net includes the carrying amount of our 3.25% Senior Notes due March 2016 and 2.75% Contingent Convertible Senior Notes due 2035. Holders of the 2.75% Contingent Convertible Senior Notes due 2035 could exercise their individual demand purchase rights on November 15, 2015, which would require us to repurchase all or a portion of the principal amount of the notes. As of June 30, 2015, current maturities of long-term debt, net reflects $7 million of discount associated with the equity component of the 2.75% Contingent Convertible Senior Notes due 2035.

For further discussion and details regarding our senior notes and contingent convertible senior notes, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

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Credit Risk

Derivative instruments that enable us to manage our exposure to oil, natural gas and NGL prices, as well as to 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, 2015, our oil, natural gas, interest rate and supply contract derivative instruments were spread among 17 counterparties. We also invested available cash balances with many of these same counterparties as well as other relationship banks. Additionally, the counterparties under our commodity hedging arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($1.008 billion as of June 30, 2015) and exploration and production companies that own interests in properties we operate ($354 million as of June 30, 2015). 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. Additionally, during the Current Period, we recorded a $13 million impairment of a note receivable as a result of the increased credit risk associated with declining commodity prices.

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, 2015, these arrangements and transactions included (i) operating lease agreements, (ii) volumetric production payments (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 4 and 9 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, 2015 vs. June 30, 2014

General. For the Current Quarter, Chesapeake had a net loss of $4.090 billion, or $6.27 per diluted common share, on total revenues of $3.033 billion. This compares to net income of $230 million, or $0.22 per diluted common share, on total revenues of $5.152 billion during the Prior Quarter. The decrease in net income in the Current Quarter was primarily driven by an impairment of our oil and natural gas properties. See Impairment of Oil and Natural Gas Properties below. The decrease in total revenues in the Current Quarter was primarily driven by decreases in the prices we received for our oil, natural gas and NGL production.

Oil, Natural Gas and NGL Sales. During the Current Quarter, oil, natural gas and NGL sales were $728 million compared to $1.704 billion in the Prior Quarter. In the Current Quarter, Chesapeake sold 64 mmboe for $776 million at a weighted average price of $12.13 per boe (excluding the effect of derivatives), compared to 63 mmboe sold in the Prior Quarter for $1.917 billion at a weighted average price of $30.32 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 $1.164 billion decrease in revenues, and increased sales volumes resulted in a $23 million increase in revenues, for a net decrease in revenues of $1.141 billion (excluding the effect of derivatives).

For the Current Quarter, our average price received per barrel of oil (excluding the effect of derivatives) was $51.21, compared to $97.49 in the Prior Quarter. Natural gas prices received per mcf (excluding the effect of derivatives) were $0.75 and $2.76 in the Current Quarter and the Prior Quarter, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $1.90 and $21.03 in the Current Quarter and the Prior Quarter, respectively.

Gains and losses from our oil and natural gas derivatives resulted in net decreases in oil and natural gas revenues of $48 million in the Current Quarter and $213 million in the Prior Quarter. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a complete listing of all of our derivative instruments as of June 30, 2015.

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A change in oil, natural gas 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 $1.00 per barrel of oil sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $11 million, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $27 million, and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease in Current Quarter revenues and cash flows of $7 million.

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

	Three Months Ended June 30, 2015								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[(a)]	(bcf)	($/mcf)[(a)]	(mmbbl)	($/bbl)[(a)]	(mmboe)	%	($/boe)[(a)]
Southern[(b)]	8.9	53.18	147.6	0.84	4.1	6.87	37.4	58	16.55
Northern[(c)]	2.0	42.84	127.8	0.64	3.1	(4.37)	26.6	42	5.90
Total	10.9	51.21	275.4	0.75	7.2	1.90	64.0	100%	12.13

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

(a) Average sales prices exclude gains (losses) on derivatives. The decrease in the average sales price for our oil sold in the Current Quarter as compared to the Prior Quarter was primarily driven by lower West Texas Intermediate (WTI) crude oil prices. The decrease in the average sales price for our natural gas sold in the Current Quarter as compared to the Prior Quarter was primarily driven by lower Henry Hub natural gas prices partially offset by lower basis differentials in certain of our operating areas relative to the Henry Hub benchmark natural gas price and lower gathering and transportation costs in certain of our operating areas. The decrease in the average sales price for our NGL sold in the Current Quarter as compared to the Prior Quarter was primarily driven by a decrease in ethane and propane prices due to seasonality in the Utica Shale play.

(b) Our Southern Division includes the Eagle Ford, Granite Wash, Cleveland, Tonkawa and Mississippian 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, 2014. Production for the Eagle Ford Shale for the Current Quarter and the Prior Quarter was 9.6 mmboe and 8.3 mmboe, respectively. The Barnett Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2014. Production for the Barnett Shale for the Current Quarter and the Prior Quarter was 5.4 mmboe and 6.2 mmboe, respectively. Our gathering agreements for Barnett and Haynesville production require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. We anticipate incurring shortfall fees of approximately $160 million to $180 million in the 2015 fourth quarter based on current production estimates.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play.

Our average daily production of 703 mboe for the Current Quarter consisted of approximately 198,700 bbls of liquids, including approximately 119,500 bbls of oil (17% on an oil equivalent basis) and approximately 79,200 bbls of NGL (11% on an oil equivalent basis) and approximately 3.0 bcf of natural gas (72% on an oil equivalent basis). Oil production increased by 5% year over year, natural gas production increased by 2% and NGL production decreased by 6%.

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

	Three Months Ended June 30,	
	2015	2014
Oil	72%	53%
Natural gas	27%	39%
NGL	1%	8%
Total	100%	100%

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 8 in Item 1 of Part I of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses 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 $2.305 billion in marketing, gathering and compression revenues in the Current Quarter, of which $220 million related to gains on the fair value of our supply contract derivatives, with corresponding expenses of $2.096 billion, for a net margin before depreciation of $209 million. This compares to revenues of $3.167 billion, expenses of $3.166 billion and a net margin before depreciation of $1 million in the Prior Quarter. Revenues and expenses decreased in the Current Quarter compared to the Prior Quarter primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations. The margin increase in the Current Quarter as compared to the Prior Quarter was primarily the result of a gain on the fair value adjustment on our supply contract derivatives, partially offset by lower compression revenues and expense as a result of the sale of a significant portion of our compression assets in 2014.

Oilfield Services Revenues and Expenses. Our oilfield services consisted of third-party revenues and expenses related to our former oilfield services operations and excluded 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 in the Prior Quarter. Chesapeake recognized revenues of $281 million, expenses of $212 million with a net margin before depreciation of $69 million in the Prior Quarter. As a result of the spin-off of our oilfield services business in June 2014, we did not have oilfield services revenues and expenses in the Current Quarter and will not have oilfield services revenues and expenses in future periods.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $276 million in the Current Quarter, compared to $282 million in the Prior Quarter. On a unit-of-production basis, production expenses were $4.32 per boe in the Current Quarter compared to $4.46 per boe in the Prior Quarter. The absolute and 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 and a decrease in ad valorem expense, partially offset by new producing wells in liquid plays with higher per unit costs. Production expenses in the Current Quarter and the Prior Quarter included approximately $31 million and $38 million, or $0.48 and $0.59 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. In addition, our obligations with respect to two of our VPPs were assumed by third parties as a result of our divestiture of related properties in 2014.

Production Taxes. Production taxes were $34 million in the Current Quarter compared to $72 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.52 per boe in the Current Quarter compared to $1.14 per boe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in the Current Quarter was primarily due to a decrease in the prices received for oil, natural gas and NGL. Production taxes in the Current Quarter and the Prior Quarter included approximately $1 million and $6 million, or $0.02 and

$0.09 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. In addition, our obligations with respect to two of our VPPs were assumed by third parties as a result of our divestiture of related properties in 2014.

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General and Administrative Expenses. General and administrative expenses were $69 million in the Current Quarter and $90 million in the Prior Quarter, or $1.08 and $1.43 per boe, respectively. The absolute and per unit expense decrease in the Current Quarter was primarily due to reduced overhead as a result of the spin-off of our oilfield services business in June 2014 and efforts to reduce other administrative expenses. In addition, in the Current Quarter, we recorded negative fair value adjustments to performance share units (PSUs) granted to executives of the Company, which corresponded to a decrease in the trading price of our common stock. See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our share-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas 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 $65 million and $55 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our oil and natural gas property acquisition and drilling and completion efforts. The increase was primarily due to capitalized payroll related costs as well as an increase in overhead.

Restructuring and Other Termination Costs. We recorded a credit of $4 million and an expense of $33 million in the Current Quarter and the Prior Quarter, respectively, for restructuring and other termination costs. The Current Quarter amount is related to negative fair value adjustments to PSUs granted to former executives of the Company, which corresponded to a decrease in the trading price of our common stock. The Prior Quarter amount primarily related to charges incurred in connection with the spin-off of our oilfield services business, senior management separations and positive fair value adjustments to PSUs granted to former executives of the Company, which corresponded to an increase in the trading price of our common stock.

Provision for Legal Contingencies. In the Current Quarter, we recorded a $334 million provision for legal contingencies. We recorded a charge of $339 million related to litigation regarding our early redemption of our 2019 notes. Additionally, we reduced our royalty provision accrual from $119 million to $114 million to reflect potential claimants that have opted out of the settlement. 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 litigation.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $601 million and $661 million in the Current Quarter and the Prior Quarter, respectively. 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 $9.39 and $10.45 in the Current Quarter and the Prior Quarter, respectively. The absolute and per unit decrease in the Current Quarter was the result of a lower amortization base as a result of our impairment of oil and gas properties in the 2015 first quarter and a reduction in our estimated future development costs as a result of drilling efficiencies, partially offset by an approximate 8% reduction in our reserve base driven primarily by lower prices used in calculating our estimated reserves. Approximately 50% of the reduction in our reserve base due to price was associated with proved undeveloped reserves. There were no other significant changes in the reserve estimates.

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Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $34 million in the Current Quarter compared to $79 million in the Prior Quarter. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. In the Prior Quarter, 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 oil and natural gas properties as drilling and completion costs. In June 2014, we completed the spin-off of our oilfield services business and, therefore, did not incur oilfield services depreciation expense in the Current Quarter and will not incur this 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
	2015	2014	Useful Life
	($ in millions)		(in years)
Natural gas compressors[(a)]	$11	$9	3 – 20
Buildings and improvements	9	12	10 – 39
Computers and office equipment	6	8	3 – 7
Vehicles	3	7	0 – 7
Natural gas gathering systems and treating plants[(a)]	3	3	20
Oilfield services equipment[(b)]	—	37	3 – 15
Other	2	3	2 – 20
Total depreciation and amortization of other assets	$34	$79	

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

Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. As of June 30, 2015, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment in the carrying value of our oil and natural gas properties of $5.015 billion. Cash flow hedges as of June 30, 2015, which related to future periods, increased the ceiling test impairment by $190 million.

As of June 30, 2015, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $12.329 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of June 30, 2015 were $71.56 per bbl of oil and $3.39 per mcf of natural gas, before price differential adjustments. Based on first-of-the-month index prices for July and August 2015, as well as the current strip prices for September 2015, we reasonably expect a decrease of approximately $12.31 per barrel of oil and $0.33 per mcf of natural gas in the prices we will be using to calculate the estimated future net revenue of our proved reserves as of September 30, 2015, and such decreases are expected to reduce the present value of estimated future net revenue of our proved reserves by approximately $4.1 billion in the 2015 third quarter. Such decrease is likely to be a significant factor in the amount of impairment recorded as of September 30, 2015. In addition, we reasonably expect a further reduction of our estimated proved reserves of approximately 8% in the 2015 third quarter, solely related to price declines. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

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Impairments of Fixed Assets and Other. In the Current Quarter and the Prior Quarter, we recognized $84 million and $40 million, respectively, of fixed asset impairment losses and other charges. The Current Quarter amount consisted of a $47 million loss contingency related to contract disputes, a $21 million impairment related to third-party rental compressors pending sale, a $13 million impairment of a note receivable and $3 million of charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices. Further contract termination charges in subsequent quarters will occur if commodity prices remain low. The Prior Quarter losses were primarily related to charges recorded for a joint venture net acreage shortfall and impairments related to a gathering system. See Note 13 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) Losses on Sales of Fixed Assets. In the Current Quarter, net losses on sales of fixed assets were $1 million compared to net gains of $93 million in the Prior Quarter. The Prior Quarter amount was primarily related to the sale of natural gas compressors.

Interest Expense. Interest expense was $71 million in the Current Quarter compared to $27 million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2015	2014
	($ in millions)	
Interest expense on senior notes	$171	$184
Interest expense on term loan	—	7
Amortization of loan discount, issuance costs and other	12	16
Interest expense on credit facilities	3	9
Realized gains on interest rate derivatives[(a)]	(1)	(3)
Unrealized gains on interest rate derivatives[(b)]	—	(31)
Capitalized interest	(114)	(155)
Total interest expense	$71	$27
Average senior notes borrowings	$11,798	$12,196
Average term loan borrowings	$—	$527
Average credit facilities borrowings	$—	$434

(a) Includes settlements related to the interest accrual for the period 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.

The increase in the Current Quarter interest expense was primarily due to a decrease in capitalized interest and a decrease in unrealized gains on interest rate derivatives, partially offset by a decrease in senior note and term loan interest expense. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.12 per boe in the Current Quarter compared to $0.92 per boe in the Prior Quarter.

Losses on Investments. Losses on investments were $17 million in the Current Quarter compared to $24 million in the Prior Quarter. The Current Quarter and the Prior Quarter losses were primarily related to our equity in FTS International, Inc. See Note 10 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our investments.

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Losses on Purchases of Debt. In the Prior Quarter, we repaid 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 Prior 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 Prior 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.

Other Income (Expense). We recorded $1 million of other expense in the Current Quarter and $7 million of other income in the Prior Quarter. The Current Quarter consisted of $2 million of miscellaneous expense and $1 million of interest income and the Prior Quarter consisted of $7 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $1.506 billion in the Current Quarter and income tax expense of $141 million in the Prior Quarter. Our effective income tax rate was 26.9% in the Current Quarter and 38.1% in the Prior Quarter. The decrease in the effective income tax rate from the Prior Quarter to the Current Quarter is primarily due to the tax benefit at expected rates being offset by a significant increase in the valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Based on the expected material write-downs of the carrying value of our oil and natural gas properties and our operating results in subsequent quarters, we project being in a net deferred tax asset position at year end. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the three-year period ending December 31, 2015. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $18 million and $39 million in the Current Quarter and the Prior Quarter, respectively. Net income attributable to noncontrolling interests in the Current Quarter consisted of income related to the Chesapeake Granite Wash Trust and the dividends paid on preferred stock of our CHK C-T subsidiary. The Prior Quarter amount included income related to the Chesapeake Granite Wash Trust as well as dividends paid on preferred stock of our CHK C-T and CHK Utica, L.L.C. (CHK Utica) subsidiaries. The decrease from the Prior Quarter to the Current Quarter is primarily due to the repurchase of all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders in July 2014. See Note 6 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.

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Results of Operations – Six Months Ended June 30, 2015 vs. June 30, 2014

General. For the Current Period, Chesapeake had a net loss of $7.810 billion, or $11.99 per diluted common share, on total revenues of $5.793 billion. This compares to net income of $696 million, or $0.78 per diluted common share, on total revenues of $10.198 billion during the Prior Period. The decrease in net income in the Current Period was primarily driven by impairments of our oil and natural gas properties. See Impairment of Oil and Natural Gas Properties below. The decrease in total revenues in the Current Period was primarily driven by decreases in the prices we received for our oil, natural gas and NGL production.

Oil, Natural Gas and NGL Sales. During the Current Period, oil, natural gas and NGL sales were $1.813 billion compared to $3.471 billion in the Prior Period. In the Current Period, Chesapeake sold 126 mmboe for $1.700 billion at a weighted average price of $13.52 per boe (excluding the effect of derivatives), compared to 124 mmboe sold in the Prior Period for $4.065 billion at a weighted average price of $32.79 per boe (excluding the effect of derivatives). The decrease in the price received per boe in the Current Period compared to the Prior Period resulted in a $2.423 billion decrease in revenues, and increased sales volumes resulted in a $58 million increase in revenues, for a net decrease in revenues of $2.365 billion (excluding the effect of derivatives).

For the Current Period, our average price received per barrel of oil (excluding the effect of derivatives) was $46.16, compared to $95.59 in the Prior Period. Natural gas prices received per mcf (excluding the effect of derivatives) were $1.17 and $3.30 in the Current Period and the Prior Period, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $4.37 and $25.10 in the Current Period and the Prior Period, respectively.

Gains and losses from our oil and natural gas derivatives resulted in a net increase in oil, natural gas and NGL revenues of $113 million in the Current Period and a net decrease of $594 million in the Prior Period. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a complete listing of all of our derivative instruments as of June 30, 2015.

A change in oil, natural gas 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 $1.00 per barrel of oil sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $22 million, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $54 million, and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease in Current Period revenues and cash flows of $14 million.

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

	Six Months Ended June 30, 2015								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[(a)]	(bcf)	($/mcf)[(a)]	(mmbbl)	($/bbl)[(a)]	(mmboe)	%	($/boe)[(a)]
Southern[(b)]	18.0	47.78	289.3	1.10	7.9	6.34	74.2	59	16.59
Northern[(c)]	3.8	38.49	249.9	1.25	6.1	1.81	51.5	41	9.10
Total	21.8	46.16	539.2	1.17	14.0	4.37	125.7	100 %	13.52

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

(a) Average sales prices exclude gains (losses) on derivatives. The decrease in the average sales price for our oil sold in the Current Period as compared to the Prior Period was primarily driven by lower WTI crude oil prices. The decrease in the average sales price for our natural gas sold in the Current Period as compared to the Prior Period was primarily driven by lower Henry Hub natural gas prices in addition to higher basis differentials in certain of our operating areas relative to the Henry Hub benchmark natural gas price and increased gathering and transportation costs in certain of our operating areas. The decrease in the average sales price for our NGL sold in the Current Period as compared to the Prior Period was primarily driven by a decrease in the Current Quarter in ethane and propane prices due to seasonality in the Utica Shale play.

(b) Our Southern Division includes the Eagle Ford, Granite Wash, Cleveland, Tonkawa and Mississippian 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, 2014. Production for the Eagle Ford Shale for the Current Period and the Prior Period was 19.8 mmboe and 16.2 mmboe, respectively. The Barnett Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2014. Production for the Barnett Shale for the Current Period and the Prior Period was 10.6 mmboe and 12.7 mmboe, respectively. Our gathering agreements for Barnett and Haynesville production require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. We anticipate incurring shortfall fees of approximately $160 million to $180 million in the 2015 fourth quarter based on current production estimates.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play.

Our average daily production of 695 mboe for the Current Period consisted of approximately 198,200 bbls of liquids, including approximately 120,700 bbls of oil (18% on an oil equivalent basis) and approximately 77,500 bbls of NGL (11% on an oil equivalent basis) and approximately 3.0 bcf of natural gas (71% on an oil equivalent basis). Oil production increased by 8% year over year, natural gas production increased by 1% and NGL production decreased by 8%.

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

	Six Months Ended June 30,	
	2015	2014
Oil	59%	48%
Natural gas	38%	43%
NGL	3%	9%
Total	100%	100%

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 8 in Item 1 of Part I of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses 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 $3.980 billion in marketing, gathering and compression revenues in the Current Period, of which $220 million related to gains on the fair value of our supply contract derivatives, with corresponding expenses of $3.796 billion, for a net margin before depreciation of $184 million. This compares to revenues of $6.182 billion, expenses of $6.147 billion and a net margin before depreciation of $35 million in the Prior Period. Revenues and expenses decreased in the Current Period compared to the Prior Period primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations. The margin increase in the Current Period as compared to the Prior Period was primarily the result of a gain on the fair value adjustment on our supply contract derivatives, partially offset by cost increases on certain sales contracts with third parties entered into to help meet certain of our oil pipeline and other commitments and by lower compression revenues and expenses as a result of the sale of a significant portion of our compression assets in 2014.

Oilfield Services Revenues and Expenses. Our oilfield services consisted of third-party revenues and expenses related to our former oilfield services operations and excluded 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 in the Prior Period. Chesapeake recognized revenues of $545 million, expenses of $431 million with a net margin before depreciation of $114 million in the Prior Period. As a result of the spin-off of our oilfield services business in June 2014, we did not have oilfield services revenues and expenses in the Current Period and will not have oilfield services revenues and expenses in future periods.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $575 million in the Current Period, compared to $570 million in the Prior Period. On a unit-of-production basis, production expenses were $4.58 per boe in the Current Period compared to $4.59 per boe in the Prior Period. The slight per unit decrease in the Current Period was primarily the result of operating efficiencies across most of our operating areas, partially offset by new producing wells in liquid plays with higher per unit costs. Production expenses in the Current Period and the Prior Period included approximately $63 million and $80 million, or $0.50 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 operating efficiencies generally improve. In addition, our obligations with respect to two of our VPPs were assumed by third parties as a result of our divestiture of related properties in 2014.

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Production Taxes. Production taxes were $62 million in the Current Period compared to $122 million in the Prior Period. On a unit-of-production basis, production taxes were $0.49 per boe in the Current Period compared to $0.99 per boe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in the Current Period was primarily due to lower prices received for oil, natural gas and NGL. Production taxes in the Current Period and Prior Period included approximately $3 million and $10 million, or $0.03 and $0.08 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. In addition, our obligations with respect to two of our VPPs were assumed by third parties as a result of our divestiture of related properties in 2014.

General and Administrative Expenses. General and administrative expenses were $125 million in the Current Period and $169 million in the Prior Period, or $1.00 and $1.37 per boe, respectively. The absolute and per unit expense decrease in the Current Period was primarily due to reduced overhead as a result of the spin-off of our oilfield services business in June 2014 and efforts to reduce other administrative expenses. In addition, in the Current Period, we recorded negative fair value adjustments to PSUs granted to executives of the Company, which corresponded to a decrease in the trading price of our common stock. See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our share-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas 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 $113 million and $112 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our oil and natural gas property acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded a credit of $14 million and an expense of $26 million in the Current Period and the Prior Period, respectively, related to restructuring and other termination costs. The Current Period amount is related to negative fair value adjustments to PSUs granted to former executives of the Company, which corresponded to a decrease in the trading price of our common stock. The Prior Period amount primarily related to charges incurred in connection with the spin-off of our oilfield services business, senior management separations and positive fair value adjustments to PSUs granted to former executives of the Company, which corresponded to an increase in the trading price of our common stock.

Provision for Legal Contingencies. In the Current Period, we recorded a $359 million provision for legal contingencies. The provision consists of $25 million related to the April 2015 resolution of litigation we were defending against the state of Michigan and $339 million related to litigation involving our early redemption of our 2019 notes. Additionally, we reduced our royalty provision accrual from $119 million to $114 million to reflect potential claimants that have opted out of the settlement. 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 litigation.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. DD&A of oil, natural gas and NGL properties was $1.285 billion and $1.288 billion in the Current Period and the Prior Period, respectively. 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 $10.22 and $10.39 in the Current Period and the Prior Period, respectively. The absolute and per unit decrease in the Current Period was the result of a lower amortization base as a result of our impairment of oil and gas properties in the 2015 first quarter and a reduction in our estimated future development costs as a result of drilling efficiencies, partially offset by an approximate 9% reduction in our reserve base driven primarily by lower prices used in calculating our estimated reserves. Approximately 45% of the reduction in our reserves base due to price was associated with proved undeveloped reserves. There were no other significant changes in the reserve estimates.

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Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $69 million in the Current Period compared to $157 million in the Prior Period. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. In the Prior Period, 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 oil and natural gas properties as drilling and completion costs. In June 2014, we completed the spin-off of our oilfield services business and, therefore, did not incur oilfield services depreciation expense in the Current Period and will not incur this 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 Useful Life
	2015	2014	
	($ in millions)		(in years)
Natural gas compressors[(a)]	$21	$17	3 – 20
Buildings and improvements	19	22	10 – 39
Computers and office equipment	13	17	3 – 7
Vehicles	6	14	0 – 7
Natural gas gathering systems and treating plants[(a)]	5	6	20
Oilfield services equipment[(b)]	—	74	3 – 15
Other	5	7	2 – 20
Total depreciation and amortization of other assets	$69	$157	

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

Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. As of June 30, 2015 and March 31, 2015, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment in the carrying value of our oil and natural gas properties of $9.991 billion. Cash flow hedges as of June 30, 2015 and March 31, 2015, which related to future periods, increased the ceiling test impairment by $385 million.

As of June 30, 2015, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $12.329 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of June 30, 2015 were $71.56 per bbl of oil and $3.39 per mcf of natural gas, before price differential adjustments. Based on first-of-the-month index prices for July and August 2015, as well as the current strip prices for September 2015, we reasonably expect a decrease of approximately $12.31 per barrel of oil and $0.33 per mcf of natural gas in the prices we will be using to calculate the estimated future net revenue of our proved reserves as of September 30, 2015, and such decreases are expected to reduce the present value of estimated future net revenue of our proved reserves by approximately $4.1 billion in the 2015 third quarter. Such decrease is likely to be a significant factor in the amount of impairment recorded as of September 30, 2015. In addition, we reasonably expect a further reduction of our estimated proved reserves of approximately 8% in the 2015 third quarter, solely related to price declines. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

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Impairments of Fixed Assets and Other. In the Current Period and the Prior Period, we recognized $88 million and $60 million, respectively, of fixed asset impairment losses and other charges. The Current Period amount consisted of a $47 million loss contingency related to contract disputes, a $21 million impairment related to third-party rental compressors pending sale, a $13 million impairment of a note receivable and $7 million of charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices. Further contract termination charges in subsequent quarters will occur if commodity prices remain low. The Prior Period losses were 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 and equipment. See Note 13 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) Losses on Sales of Fixed Assets. In the Current Period, net losses on sales of fixed assets were $4 million compared to net gains of $115 million in the Prior Period. The Prior Period amount was primarily related to the sale of natural gas compressors.

Interest Expense. Interest expense was $122 million in the Current Period compared to $66 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2015	2014
	($ in millions)	
Interest expense on senior notes	$342	$364
Interest expense on term loan	—	36
Amortization of loan discount, issuance costs and other	23	35
Interest expense on credit facilities	6	17
Realized gains on interest rate derivatives[(a)]	(2)	(6)
Unrealized gains on interest rate derivatives[(b)]	(10)	(47)
Capitalized interest	(237)	(333)
Total interest expense	$122	$66
Average senior notes borrowings	$11,798	$11,506
Average term loan borrowings	$—	$1,260
Average credit facilities borrowings	$—	$437

(a) Includes settlements related to the interest accrual for the period 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.

The increase in the Current Period interest expense was primarily due to a decrease in capitalized interest and a decrease in unrealized gains on interest rate derivatives, partially offset by a decrease in senior note and term loan interest expense. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.05 per boe in the Current Period compared to $0.91 per boe in the Prior Period.

Losses on Investments. Losses on investments were $24 million in the Current Period compared to $45 million in the Prior Period. The Current Period and the Prior Period losses were primarily related to our equity in FTS International, Inc. See Note 10 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our investments.

Net Gain on Sales of Investments. We recorded a net gain on sales of investments of $67 million in the Prior 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.

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Losses on Purchases of Debt. In the Prior Period, we repaid 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 Prior 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 Prior 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.

Other Income. Other income was $5 million in the Current Period, consisting of $3 million of interest income and $2 million of miscellaneous income. In the Prior Period, other income was $13 million and consisted primarily of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $2.878 billion in the Current Period and income tax expense of $421 million in the Prior Period. Our effective income tax rate was 26.9% in the Current Period and 37.7% in the Prior Period. The decrease in the effective income tax rate from the Prior Period to the Current Period is primarily due to the tax benefit at expected rates being offset by a significant increase in the valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Based on the expected material write-downs of the carrying value of our oil and natural gas properties and our operating results in subsequent quarters, we project being in a net deferred tax asset position at year end. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the three-year period ending December 31, 2015. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $37 million and $80 million in the Current Period and the Prior Period, respectively. Net income attributable to noncontrolling interests in the Current Period consisted of income related to the Chesapeake Granite Wash Trust and the dividends paid on preferred stock of our CHK C-T subsidiary. The Prior Period amount included income related to the Chesapeake Granite Wash Trust as well as dividends paid on preferred stock of our CHK C-T and CHK Utica subsidiaries. The decrease from the Prior Period to the Current Period is primarily due to the repurchase of all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders in July 2014. See Note 6 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.

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 oil, natural gas and NGL production and future expenses, estimated operating costs, assumptions regarding future oil, natural gas and NGL prices, planned drilling activity, estimates of future drilling and completion and other capital expenditures, potential future write-downs of our oil and natural gas assets, anticipated sales, and the adequacy of our provisions for legal contingencies, as well as statements concerning anticipated cash flow and liquidity, ability to comply with financial maintenance covenants and meet contractual commitments to third parties, 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. Our plans to reduce financial complexity may take longer to implement if such divestitures 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.

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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 annual report on Form 10-K for the year ended December 31, 2014 ("2014 Form 10-K") and include:

- the volatility of oil, natural gas and NGL prices;
- write-downs of our oil and natural gas asset carrying values due to declines in prices;
- the availability of operating cash flow and other funds to finance reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- 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 oil, natural gas and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- the limitations our level of indebtedness may have on our financial flexibility;
- charges incurred in response to market conditions and in connection with actions to reduce financial leverage and complexity;
- drilling and operating risks and resulting liabilities;
- effects of environmental protection laws and regulation on our business;
- legislative and regulatory initiatives further regulating hydraulic fracturing;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- federal and state tax proposals affecting our industry;
- potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations;
- impacts of potential legislative and regulatory actions addressing climate change;
- competition in the oil and gas exploration and production industry;
- a deterioration in general economic, business or industry conditions;
- negative public perceptions of our industry;
- limited control over properties we do not operate;
- pipeline and gathering system capacity constraints and transportation interruptions;
- 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

Oil, Natural Gas and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas 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 oil, natural gas and NGL price changes is to hedge into strengthening oil and natural gas 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, oil and natural gas 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 swaps and three-way collars for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility. In 2012 and 2013, we bought oil and natural gas calls to, in effect, lock in sold call positions. Due to lower oil, natural gas 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 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 share of 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 commodity 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 this 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 review 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. This 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 commodity hedging arrangements which require 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 8 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.

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As of June 30, 2015, our oil and natural gas 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 the excess on sold call options, and Chesapeake receives the 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, 2015, we had the following open oil and natural gas derivative instruments:

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps:						
Short-term	7.4	$86.94	$—	$—	$—	$196
3-Way Collars:						
Short-term	2.2	—	98.94	80.00 / 90.00	—	21
Call Options (sold):						
Short-term	17.6	—	102.83	—	—	(3)
Long-term	14.8	—	97.13	—	—	(17)
Call Options (bought)[(a)]:						
Short-term	(4.5)	—	113.54	—	—	(6)
Basis Protection Swaps:						
Short-term	4.5	—	—	—	3.31	4
	Total Oil					$195

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	Volume (tbtu)	Weighted Average Price Fixed ($ per mmbtu)	Call	Put	Differential	Fair Value Asset (Liability) ($ in millions)
Natural Gas:						
Swaps:						
Short-term	214	$3.64	$—	$—	$—	$135
Long-term	46	3.20				—
3-Way Collars:						
Short-term	71	—	4.37	3.38 / 4.17	—	51
Call Options (sold):						
Short-term	253	—	6.53	—	—	(3)
Long-term	254	—	8.60	—	—	(4)
Call Options (bought)(b):						
Short-term	(214)	—	6.17	—	—	(81)
Long-term	(100)	—	6.02	—	—	(40)
Basis Protection Swaps:						
Short-term	59	—	—	—	(0.50)	10
Long-term	21	—	—	—	(0.55)	(5)
Total Natural Gas						$63
Total Oil and Natural Gas						$258

(a) Included in the fair value are deferred premiums of $7 million which will be included in oil, natural gas and NGL sales as realized gains (losses) in the remainder of 2015.

(b) Included in the fair value are deferred premiums of $42 million and $85 million which will be included in oil, natural gas and NGL sales as realized gains (losses) in the remainder of 2015 and 2016, respectively.

In addition to the open derivative positions disclosed above, as of June 30, 2015, we had $127 million of net derivative gains related to settled contracts for future production periods that will be recorded within oil, natural gas 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, 2015 ($ in millions)
Short-term	$117
Long-term	10
Total	$127

The table below reconciles the changes in fair value of our oil and natural gas derivatives during the Current Period. Of the $258 million fair value asset as of June 30, 2015, a $324 million asset relates to contracts maturing in the next 12 months and a $66 million liability relates to contracts maturing after 12 months. All open derivative instruments as of June 30, 2015 are expected to mature by December 31, 2022.

	June 30, 2015 ($ in millions)
Fair value of contracts outstanding, as of January 1	$721
Change in fair value of contracts	135
Contracts realized or otherwise settled	(598)
Fair value of contracts outstanding, as of June 30	$258

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The change in oil and natural gas prices during the Current Period increased the asset related to our derivative instruments by $135 million. This unrealized gain is recorded in oil, natural gas and NGL sales. We settled contracts in the Current Period that were in an asset position for $598 million. The realized gains will be recorded in oil, natural gas 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, using the earliest demand repurchase date for contingent convertible senior notes. As of June 30, 2015, we had total debt of $11.7 billion, including $10.2 billion of fixed rate debt at interest rates averaging 5.24% and $1.5 billion of floating rate debt at an interest rate of 3.53% (three-month LIBOR plus 3.25%).

	Years of Maturity						
	2015	2016	2017	2018	2019	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$396	$500	$2,212	$1,016	$—	$6,100	$10,224
Average interest rate	2.75 %	3.25 %	4.35 %	5.54 %	— %	5.83 %	5.24 %
Debt – variable rate	$—	$—	$—	$—	$1,500	$—	$1,500
Average interest rate	— %	— %	— %	— %	3.53 %	— %	3.53 %

(a) This amount does not include the discount included in debt of $188 million and interest rate derivatives of $8 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 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.

From time to time, 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 revolving credit facility borrowings. As of June 30, 2015, 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)
Floating to Fixed:					
Swaps					
Mature 2015	$400	2.59 %	6 mL	No	$—

(a) Month LIBOR has been abbreviated “mL”.

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In addition to the open derivative positions disclosed above, as of June 30, 2015, we had $44 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains or losses once they are transferred from our senior note liability or within interest expense as unrealized gains or losses over the remaining eight-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 sheets as liabilities of $88 million and $53 million as of June 30, 2015 and December 31, 2014, respectively. The euro-denominated debt in long-term debt has been adjusted to $384 million as of June 30, 2015, using an exchange rate of $1.1147 to €1.00.

Supply Contract Derivatives

As discussed in Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, we enter into supply contracts in the normal course of business under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas thereby creating an embedded derivative. The prices of the products other than natural gas are unobservable. We engage an independent third party valuation firm to value these supply contracts. The products being valued other than natural gas are sensitive to pricing fluctuations and some of these fluctuations could be material. Changes to the value of these contracts are recorded as mark-to-market adjustments to marketing, gathering and compression revenues in our condensed consolidated financial statements.

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, 2015.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the period ended June 30, 2015, which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

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PART II

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 4 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 Litigation. 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. On appeal, the U.S. Court of Appeals for the Tenth Circuit affirmed the dismissal on August 8, 2014 and denied the plaintiff’s petition for rehearing on November 12, 2014. On April 10, 2015, the plaintiffs filed a writ of certiorari with the United States Supreme Court.

Shareholder Derivative Litigation. A federal consolidated derivative action and an Oklahoma state court derivative action were stayed in 2012 pending resolution of a related, previously reported putative federal securities class action. The shareholder derivative actions allege breaches of fiduciary duty, among other things, related to the former CEO’s personal financial practices and purported conflicts of interest, and the Company’s accounting for VPPs. With the dismissal of the federal securities class action now affirmed (in July 2014), the parties stipulated to continue the stay of the Oklahoma state court derivative action while the plaintiffs pursue their claims in the federal consolidated derivative action. The plaintiffs filed a consolidated derivative complaint on October 31, 2014 and an amended consolidated derivative complaint on February 12, 2015. Chesapeake filed its motion to dismiss on February 23, 2015.

Regulatory Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and gas rights in various states. The Company also has received DOJ and state subpoenas seeking information on the Company’s royalty payment practices. Chesapeake has engaged in discussions with the DOJ and state agency representatives 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 89^{th} 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 in the same court on June 5, 2014 which, as amended, alleged that Chesapeake’s conduct in canceling lease offers to Michigan landowners in 2010 violated the state’s criminal enterprises and false pretenses felony statutes. In resolution of both criminal complaints and with no admission of wrongdoing, on April 24, 2015, the Company entered a plea of no contest to one count of misdemeanor attempted antitrust violation and one count of misdemeanor false pretenses. The plea has been taken under advisement for a period of 11 months by the Court and will be dismissed if Chesapeake fulfills the terms of a settlement agreement with the Attorney General. As part of the settlement, Chesapeake will contribute no more than $25 million to a compensation fund established to compensate Michigan landowners for unfunded oil and gas leases in 2010.

Redemption of 2019 Notes. See Chesapeake Senior Notes and Contingent Convertible Senior Notes in Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a description of pending litigation regarding our redemption in May 2013 of our 2019 Notes.

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 oil and natural gas 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 will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

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 with respect to royalty underpayment in various states, including, but not limited to, Oklahoma, Texas, Pennsylvania, Ohio, Louisiana and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ and state subpoenas seeking information on the Company's royalty payment practices.

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 putative class action filed in November 2010 in the District Court of Beaver County, Oklahoma 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. We and the named plaintiff participated in mediation concerning the claims asserted in the putative class action litigation, and in the Current Period we negotiated a settlement requiring the Company to pay $119 million cash to compensate the putative settlement class for alleged past royalty underpayments in exchange for the release of claims for the ten-year period ended December 31, 2014. Following a fairness hearing, the District Court certified the settlement class and approved the $119 million settlement on July 3, 2015. The Company reduced its prior settlement accrual to $114 million in the Current Quarter to reflect potential claimants that have opted out of the settlement. Although Chesapeake believes its royalty calculation and payment methodologies are appropriate under Oklahoma oil and gas law and denies that it committed any acts or omissions giving rise to any liability, it also believes that settlement is in the best interest of the Company considering the questions of law and fact involved and the uncertainty of continued litigation.

Chesapeake is also defending lawsuits alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order from the Texas Multidistrict Litigation Panel to transfer a substantial portion of these lawsuits filed since June 2014 to the 348th District Court of Tarrant County for pre-trial purposes. These lawsuits, which are primarily related to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. In addition to allegations of breach of contract, a number of these lawsuits allege fraud, conspiracy, joint venture and antitrust violations by Chesapeake. Chesapeake expects that additional lawsuits will be filed by new plaintiffs making similar allegations. The lawsuits seek direct damages in varying amounts, together with exemplary damages, attorneys' fees, costs and interest. Chesapeake believes its royalty calculations and payment practices were appropriate and has not accrued a loss contingency with respect to the multidistrict litigation.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed 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 cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and one of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws.

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Environmental Proceedings

Our subsidiary Chesapeake Appalachia, LLC (CALLC) is engaged in discussions with the U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers and the Pennsylvania Department of Environmental Protection (PADEP) regarding potential violations of the permitting requirements of the federal Clean Water Act, the Pennsylvania Clean Streams Law and the Pennsylvania Dam Safety and Encroachments Act in connection with the placement of dredge and fill material during construction of certain sites in Pennsylvania. CALLC identified the potential violations in connection with an internal review of its facilities siting and construction processes and voluntarily reported them to the regulatory agencies. Resolution of the matter may result in monetary sanctions of more than $100,000.

CALLC is also engaged in discussions with the PADEP regarding potential violations of the Pennsylvania Clean Streams Law as a result of pad subsidence allegedly causing material to enter a nearby stream. Since the incident, CALLC and the PADEP have been working to remediate the site and bring it into compliance. We expect that resolution of these matters will result in monetary sanctions of more than $100,000.

In July 2015, we settled an enforcement action initiated by the PADEP relating to alleged gas migration into the groundwater in Bradford County, Pennsylvania by agreeing to pay a civil penalty of $193,135.

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 2014 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, 2015:

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 Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs[(b)] ($ in millions)
April 1, 2015 through April 30, 2015	12,065	$14.81	—	$1,000
May 1, 2015 through May 31, 2015	24,023	$15.00	—	$1,000
June 1, 2015 through June 30, 2015	23,768	$11.93	—	$1,000
Total	59,856	$13.74	—	

(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. Also includes shares of common stock purchased on behalf of Chesapeake’s deferred compensation plan related to participant deferrals and Company matching contributions.

(b) In December 2014, the Company’s Board of Directors authorized the repurchase of up to $1 billion in value of its common stock from time to time. The repurchase program does not have an expiration date. As of June 30, 2015, no repurchases had been made under the program.

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ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

The exhibits listed below in the Index of Exhibits (following the signatures page) are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

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SIGNATURES

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

	CHESAPEAKE ENERGY CORPORATION	
Date: August 5, 2015	By:	/s/ ROBERT D. LAWLER Robert D. Lawler, President and Chief Executive Officer
Date: August 5, 2015	By:	/s/ DOMENIC J. DELL'OSSO, JR. Domenic J. Dell'Osso, Jr. Executive Vice President and Chief Financial Officer

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INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
3.1.1	Chesapeake's Restated Certificate of Incorporation.	10-Q	001-13726	3.1.1	8/6/2014	
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	6/9/2014	
10.1	Employment Agreement effective May 21, 2015 between Chesapeake Energy Corporation and Frank Patterson.					X
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
31.1	Robert D. Lawler, President and 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						X

	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	
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 2002.	X
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

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101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	X