CHESAPEAKE ENERGY CORP
Form 10-Q
August 03, 2017

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, 2017
or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer",

"accelerated filer", "smaller reporting company," and “emerging growth company” in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer [X]
Accelerated Filer [ ]
Non-accelerated Filer [ ] (Do not check if a smaller reporting company)
Smaller Reporting Company [ ]
Emerging Growth Company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

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, 2017, there were 908,339,499 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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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, 2017	December 31, 2016
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$13	$882
Accounts receivable, net	1,019	1,057
Short-term derivative assets	71	—
Other current assets	144	203
Total Current Assets	1,247	2,142
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)	67,419	66,451
Unproved properties	4,096	4,802
Other property and equipment	2,020	2,053
Total Property and Equipment, at Cost	73,535	73,306
Less: accumulated depreciation, depletion and amortization (($459) and ($458) attributable to our VIE)	(63,138)	(62,726)
Property and equipment held for sale, net	21	29
Total Property and Equipment, Net	10,418	10,609
LONG-TERM ASSETS:		
Long-term derivative assets	14	—
Other long-term assets	241	277
TOTAL ASSETS	$11,920	$13,028

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, 2017	December 31, 2016
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$718	$672
Current maturities of long-term debt, net	3	503
Accrued interest	137	113
Short-term derivative liabilities	3	562
Other current liabilities ($4 and $3 attributable to our VIE)	1,297	1,798
Total Current Liabilities	2,158	3,648
LONG-TERM LIABILITIES:		
Long-term debt, net	9,850	9,938
Long-term derivative liabilities	1	15
Asset retirement obligations, net of current portion	221	247
Other long-term liabilities	374	383
Total Long-Term Liabilities	10,446	10,583
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 5,603,458 and 5,839,506 shares outstanding	1,671	1,771
Common stock, $0.01 par value, 2,000,000,000 and 1,500,000,000 shares authorized: 907,977,114 and 896,279,353 shares issued	9	9
Additional paid-in capital	14,458	14,486
Accumulated deficit	(16,969)	(17,603)
Accumulated other comprehensive loss	(75)	(96)
Less: treasury stock, at cost; 2,336,327 and 1,220,504 common shares	(32)	(27)
Total Chesapeake Stockholders' Equity (Deficit)	(938)	(1,460)
Noncontrolling interests	254	257
Total Equity (Deficit)	(684)	(1,203)
TOTAL LIABILITIES AND EQUITY	$11,920	$13,028

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,	
	2017	2016	2017	2016
	($ in millions except per share data)			
REVENUES:				
Oil, natural gas and NGL	$1,279	$440	$2,748	$1,433
Marketing, gathering and compression	1,002	1,182	2,286	2,142
Total Revenues	2,281	1,622	5,034	3,575
OPERATING EXPENSES:				
Oil, natural gas and NGL production	140	182	275	388
Oil, natural gas and NGL gathering, processing and transportation	357	481	712	963
Production taxes	21	19	43	37
Marketing, gathering and compression	1,027	1,207	2,355	2,149
General and administrative	70	61	135	109
Restructuring and other termination costs	—	3	—	3
Provision for legal contingencies	17	71	15	104
Oil, natural gas and NGL depreciation, depletion and amortization	202	277	399	540
Depreciation and amortization of other assets	21	29	42	58
Impairment of oil and natural gas properties	—	1,070	—	2,067
Impairments of fixed assets and other	26	6	417	44
Net (gains) losses on sales of fixed assets	1	(1)	1	(5)
Total Operating Expenses	1,882	3,405	4,394	6,457
INCOME (LOSS) FROM OPERATIONS	399	(1,783)	640	(2,882)
OTHER INCOME (EXPENSE):				
Interest expense	(93)	(62)	(188)	(124)
Losses on investments	—	(2)	—	(2)
Loss on sale of investment	—	—	—	(10)
Gains on purchases or exchanges of debt	191	68	184	168
Other income (expense)	(1)	3	2	6
Total Other Income (Expense)	97	7	(2)	38
INCOME (LOSS) BEFORE INCOME TAXES	496	(1,776)	638	(2,844)
Income Tax Expense	1	—	2	—
NET INCOME (LOSS)	495	(1,776)	636	(2,844)
Net income attributable to noncontrolling interests	(1)	—	(2)	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	494	(1,776)	634	(2,844)
Preferred stock dividends	(16)	(42)	(39)	(85)
Loss on exchange of preferred stock	—	—	(41)	—
Earnings allocated to participating securities	(8)	—	(7)	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$470	$(1,818)	$547	$(2,929)
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$0.52	$(2.51)	$0.60	$(4.21)
Diluted	$0.47	$(2.51)	$0.59	$(4.21)
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				

Basic	908	724	907	695
Diluted	1,114	724	1,053	695

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,	
	2017	2016	2017	2016
	($ in millions)			
NET INCOME (LOSS)	$495	$(1,776)	$636	$(2,844)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:				
Unrealized gains (losses) on derivative instruments, net of income tax expense (benefit) of $0, $2, $0 and ($1)	—	(15)	4	(19)
Reclassification of losses on settled derivative instruments, net of income tax expense (benefit) of $0, ($4), $0 and $3	7	10	17	14
Other Comprehensive Income (Loss)	7	(5)	21	(5)
COMPREHENSIVE INCOME (LOSS)	502	(1,781)	657	(2,849)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(1)	—	(2)	—
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$501	$(1,781)	$655	$(2,849)

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,	
	2017	2016
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$636	$(2,844)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	441	598
Derivative (gains) losses, net	(522)	278
Cash receipts (payments) on derivative settlements, net	(66)	386
Stock-based compensation	27	25
Impairment of oil and natural gas properties	—	2,067
Net (gains) losses on sales of fixed assets	1	(5)
Impairments of fixed assets and other	1	34
Losses on investments	—	2
Loss on sale of investment	—	10
Gains on purchases or exchanges of debt	(185)	(168)
Restructuring and other termination costs	—	3
Provision for legal contingencies	15	104
Other	(59)	(51)
Changes in assets and liabilities	(347)	(765)
Net Cash Used In Operating Activities	(58)	(326)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(1,031)	(609)
Acquisitions of proved and unproved properties	(162)	(426)
Proceeds from divestitures of proved and unproved properties	951	964
Additions to other property and equipment	(7)	(25)
Proceeds from sales of other property and equipment	26	70
Cash paid for title defects	—	(69)
Other	—	(4)
Net Cash Used In Investing Activities	(223)	(99)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility borrowings	2,551	2,477
Payments on revolving credit facility borrowings	(1,976)	(2,377)
Proceeds from issuance of senior notes, net	742	—
Cash paid to purchase debt	(1,746)	(472)
Cash paid for preferred stock dividends	(137)	—
Distributions to noncontrolling interest owners	(5)	(6)
Other	(17)	(18)
Net Cash Used In Financing Activities	(588)	(396)
Net decrease in cash and cash equivalents	(869)	(821)
Cash and cash equivalents, beginning of period	882	825

Cash and cash equivalents, end of period	$13	$4

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)

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

	Six Months Ended June 30,	
	2017	2016
	($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$217	$154
Income tax refunds received, net	$(14)	$(20)
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$87	$(13)
Change in accrued acquisitions of proved and unproved properties	$4	$—
Change in divested proved and unproved properties	$16	$2
Debt exchanged for common stock	$—	$471

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, 2017	2016
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$1,771	$3,062
Exchange/conversions of 236,048 and 25,802 shares of preferred stock for common stock	(100)	(26)
Balance, end of period	1,671	3,036
COMMON STOCK:		
Balance, beginning of period	9	7
Exchange of senior notes and contingent convertible notes	—	1
Balance, end of period	9	8
ADDITIONAL PAID-IN CAPITAL:		
Balance, beginning of period	14,486	12,403
Stock-based compensation	29	31
Exchange of contingent convertible notes for 0 and 55,427,782 shares of common stock	—	241
Exchange of senior notes for 0 and 53,923,925 shares of common stock	—	229
Exchange/conversion of preferred stock for 9,965,835 and 1,021,506 shares of common stock	100	26
Equity component of contingent convertible notes repurchased	(20)	—
Dividends on preferred stock	(137)	—
Balance, end of period	14,458	12,930
RETAINED EARNINGS (ACCUMULATED DEFICIT):		
Balance, beginning of period	(17,603)	(13,202)
Net income (loss) attributable to Chesapeake	634	(2,844)
Balance, end of period	(16,969)	(16,046)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(96)	(99)
Hedging activity	21	(5)
Balance, end of period	(75)	(104)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(27)	(33)
Purchase of 1,189,813 and 22,810 shares for company benefit plans	(6)	—
Release of 73,990 and 157,514 shares from company benefit plans	1	4
Balance, end of period	(32)	(29)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT)	(938)	(205)
NONCONTROLLING INTERESTS:		
Balance, beginning of period	257	259
Net income attributable to noncontrolling interests	2	—
Distributions to noncontrolling interest owners	(5)	2
Balance, end of period	254	261
TOTAL EQUITY (DEFICIT)	$(684)	$56

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

1. Basis of Presentation

The accompanying condensed consolidated financial statements of Chesapeake Energy Corporation ("Chesapeake" or the "Company") 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, 2017 (the "Current Quarter" and the "Current Period, respectively) and the three and six months ended June 30, 2016 (the "Prior Quarter" and the "Prior Period", respectively). Chesapeake's annual report on Form 10-K for the year ended December 31, 2016 ("2016 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.

Risks and Uncertainties

Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and natural gas liquids (NGL) we produce and sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been very volatile, and may be subject to wide fluctuations in the future. The substantial decline in oil, natural gas and NGL prices from 2014 levels has negatively affected the amount of liquidity we have available for capital expenditures and debt service. A substantial or extended decline in oil, natural gas and NGL prices could have a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we may economically produce. Other risks and uncertainties that could affect us in a low commodity price environment include, but are not limited to, counterparty credit risk for our receivables, access to capital markets, regulatory risks and our ability to meet financial ratios and covenants in our financing agreements.

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

Revision of Previously Reported Condensed Consolidated Financial Statements

During the fourth quarter of 2016, we identified certain errors to the basis price differentials used in calculating the impairment of oil and natural gas properties and oil, natural gas and NGL depreciation, depletion and amortization for each of the first three interim periods in 2016. As disclosed within our 2016 Form 10-K, it was determined that these errors were not material to our previously issued 2016 interim financial statements. Accordingly, the correction of these errors and another immaterial previously identified error was reflected in the quarterly unaudited financial data included within our 2016 Form 10-K. These revisions have been reflected in the comparative 2016 condensed consolidated financial statements presented herein. See Evaluation of Disclosure Controls and Procedures in Item 4 of this Form 10-Q. The following table reconciles the amounts as previously reported in the applicable financial statement to the corresponding revised amounts:

	Three Months Ended June 30, 2016		
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS	As Previously Reported	Revision Adjustment	As Revised
	($ in millions except per share data)		
Provision for legal contingencies	$82	$ (11)	$71
Oil, natural gas and NGL depreciation, depletion and amortization	$265	$ 12	$277
Impairment of oil and natural gas properties	$1,045	$ 25	$1,070
Total operating expenses	$3,379	$ 26	$3,405
Loss from operations	$(1,757)	$ (26)	$(1,783)
Loss before income taxes	$(1,750)	$ (26)	$(1,776)
Net loss	$(1,750)	$ (26)	$(1,776)
Net loss attributable to Chesapeake	$(1,750)	$ (26)	$(1,776)
Net loss available to common stockholders	$(1,792)	$ (26)	$(1,818)
Earnings (loss) per common share basic	$(2.48)	$ (0.03)	$(2.51)
Earnings (loss) per common share diluted	$(2.48)	$ (0.03)	$(2.51)

	Six Months Ended June 30, 2016		
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS	As Previously Reported	Revision Adjustment	As Revised
	($ in millions except per share data)		
Provision for legal contingencies	$104	$ —	$104
Oil, natural gas and NGL depreciation, depletion and amortization	$536	$ 4	$540
Impairment of oil and natural gas properties	$1,898	$ 169	$2,067
Total operating expenses	$6,284	$ 173	$6,457
Loss from operations	$(2,709)	$ (173)	$(2,882)
Loss before income taxes	$(2,671)	$ (173)	$(2,844)
Net loss	$(2,671)	$ (173)	$(2,844)
Net loss attributable to Chesapeake	$(2,671)	$ (173)	$(2,844)
Net loss available to common stockholders	$(2,756)	$ (173)	$(2,929)
Earnings (loss) per common share basic	$(3.97)	$ (0.24)	$(4.21)

Earnings (loss) per common share diluted	$(3.97)	$(0.24)	$(4.21)

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)	Three Months Ended June 30, 2016 As Previously Reported	Revision Adjustment	As Revised
	($ in millions)		
Net loss	$(1,750)	$ (26)	$(1,776)
Comprehensive loss	$(1,755)	$ (26)	$(1,781)
Comprehensive loss attributable to Chesapeake	$(1,755)	$ (26)	$(1,781)

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)	Six Months Ended June 30, 2016 As Previously Reported	Revision Adjustment	As Revised
	($ in millions)		
Net loss	$(2,671)	$ (173)	$(2,844)
Comprehensive loss	$(2,676)	$ (173)	$(2,849)
Comprehensive loss attributable to Chesapeake	$(2,676)	$ (173)	$(2,849)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS	Six Months Ended June 30, 2016 As Previously Reported	Revision Adjustment	As Revised
	($ in millions)		
Net loss	$(2,671)	$ (173)	$(2,844)
Depreciation, depletion and amortization	$594	$ 4	$598
Impairment of oil and natural gas properties	$1,898	$ 169	$2,067
Provision for legal contingencies	$104	$ —	$104
Net cash used in operating activities	$(326)	$ —	$(326)

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

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 convertible senior notes and contingent convertible senior notes.

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, shares of common stock for the following dilutive securities were excluded from the calculation of diluted EPS as the effect was antidilutive.

	Shares (in millions)
Three Months Ended June 30, 2017	
Participating securities	1
Three Months Ended June 30, 2016	
Common stock equivalent of our preferred stock outstanding:	
5.75% cumulative convertible preferred stock	58
5.75% cumulative convertible preferred stock (series A)	42
5.00% cumulative convertible preferred stock (series 2005B)	6
4.50% cumulative convertible preferred stock	6
Participating securities	1
Six Months Ended June 30, 2017	
Common stock equivalent of our preferred stock outstanding:	
5.75% cumulative convertible preferred stock	31
5.75% cumulative convertible preferred stock (series A)	18
5.00% cumulative convertible preferred stock (series 2005B)	5
4.50% cumulative convertible preferred stock	6

Participating securities	1
Common stock equivalent of our preferred stock outstanding prior to exchange:	
5.75% cumulative convertible preferred stock exchanged	1
Six Months Ended June 30, 2016	
Common stock equivalent of our preferred stock outstanding:	
5.75% cumulative convertible preferred stock	58
5.75% cumulative convertible preferred stock (series A)	42
5.00% cumulative convertible preferred stock (series 2005B)	6
4.50% cumulative convertible preferred stock	6
Participating securities	1

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

For the Current Quarter and the Current Period, outstanding stock options were included in the calculation of diluted EPS. A reconciliation of basic EPS and diluted EPS is as follows:

	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended June 30, 2017			
Basic EPS	$ 470	908	$ 0.52
Effect of Dilutive Securities:			
5.75% cumulative convertible preferred stock	11	31	
5.75% cumulative convertible preferred stock (series A)	7	18	
5.00% cumulative convertible preferred stock (series 2005B)	2	5	
4.50% cumulative convertible preferred stock	3	6	
5.5% convertible senior notes due 2026	36	146	
Diluted EPS	$ 529	1,114	$ 0.47
Six Months Ended June 30, 2017			
Basic EPS	$ 547	907	$ 0.60
Effect of Dilutive Securities:			
5.5% convertible senior notes due 2026	72	146	
Diluted EPS	$ 619	1,053	$ 0.59

3. Debt

Our long-term debt consisted of the following as of June 30, 2017 and December 31, 2016:

	June 30, 2017		December 31, 2016	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
Term loan due 2021	$1,500	$1,500	$1,500	$1,500
6.25% euro-denominated senior notes due 2017[(a)]	—	—	258	258
6.5% senior notes due 2017	—	—	134	134
7.25% senior notes due 2018	46	46	64	64
Floating rate senior notes due 2019	380	380	380	380
6.625% senior notes due 2020	572	572	780	780
6.875% senior notes due 2020	279	279	279	279
6.125% senior notes due 2021	550	550	550	550
5.375% senior notes due 2021	270	270	270	270
4.875% senior notes due 2022	451	451	451	451
8.00% senior secured second lien notes due 2022[(b)]	1,737	2,385	2,419	3,409
5.75% senior notes due 2023	338	338	338	338
8.00% senior notes due 2025	1,000	1,000	1,000	1,000
5.5% convertible senior notes due 2026[(c)(e)]	1,250	824	1,250	811
8.00% senior notes due 2027	750	750	—	—
2.75% contingent convertible senior notes due 2035[(d)]	2	2	2	2
2.5% contingent convertible senior notes due 2037[(d)]	1	1	114	112
2.25% contingent convertible senior notes due 2038[(d)(e)]	9	8	200	180
Revolving credit facility	575	575	—	—
Debt issuance costs	—	(65)	—	(64)
Discount on senior notes	—	(15)	—	(16)
Interest rate derivatives[(f)]	—	2	—	3
Total debt, net	9,710	9,853	9,989	10,441
Less current maturities of long-term debt, net[(g)]	(3)	(3)	(506)	(503)
Total long-term debt, net	$9,707	$9,850	$9,483	$9,938

(a) The principal and carrying amounts shown are based on the exchange rate of $1.0517 to €1.00 as of December 31, 2016. See Foreign Currency Derivatives in Note 8 for information on our related foreign currency derivatives.

(b) The carrying amounts as of June 30, 2017 and December 31, 2016, include premium amounts of $648 million and $990 million, respectively, associated with a troubled debt restructuring. The premium is being amortized based on the effective yield method.

(c) The conversion and redemption provisions of our convertible senior notes are as follows:

Optional Conversion by Holders. Prior to maturity under certain circumstances and at the holder’s option, the notes are convertible into cash, our common stock, or a combination of cash and common stock, at our election. 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 second quarter of 2017, the price of our common stock was below the threshold level and, as a result, the holders do not have the option to convert their notes in the third quarter of 2017 under this provision. The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision during the Current Quarter. Upon conversion of a convertible senior note, the holder will receive cash, common stock or a combination of cash and common stock, at our election, according to the conversion rate specified in the indenture.

The common stock price conversion threshold amount for the convertible senior notes is 130% of the conversion price.

Optional Redemption by the Company. We may redeem the convertible senior notes for cash on or after September 15, 2019, if the price of our common stock exceeds 130% of the conversion price during a specified period at a redemption price of 100% of the principal amount of the notes.

Holders' Demand Repurchase Rights. The holders of our 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 upon certain fundamental changes.

(d) 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 and upon certain fundamental changes.

Optional Conversion by Holders. At the holder's option, prior to maturity under certain circumstances, the notes are convertible into cash and, if applicable, 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 within a fiscal quarter. Convertibility based on common stock price is measured quarterly. During the specified period in the Current Quarter, 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 or common stock in the third quarter of 2017 under this provision.

The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision during the Current Quarter and 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 contingent 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 thresholds 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, 2020, 2025, 2030	$ 45.02	May 14, 2016
2.5% due 2037	May 15, 2022, 2027, 2032	$ 59.44	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 100.20	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. In July

2017, we redeemed our remaining 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037.

(e) The carrying amounts as of June 30, 2017 and December 31, 2016, are reflected net of discounts of $427 million and $461 million, respectively, associated with the equity component of our convertible and contingent convertible senior notes. This amount is being amortized based on the effective yield method through the first demand repurchase date as applicable.

(f) See Interest Rate Derivatives in Note 8 for further discussion related to these instruments.

(g) As of June 30, 2017, current maturities of long-term debt, net includes our 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037. As discussed in footnote (d) above, we redeemed both series of these notes in July 2017.

Term Loan Facility

We have a secured five-year term loan facility in an aggregate principal amount of $1.5 billion. Our obligations under the facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility, second lien notes and senior notes and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 7.50% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 6.50% per annum, subject to a 2.00% ABR floor, at our option. The term loan matures in August 2021 and voluntary prepayments are subject to a make-whole premium prior to the second anniversary of the closing of the term loan, a premium to par of 4.25% from the second anniversary until but excluding the third anniversary, a premium to par of 2.125% from the third anniversary until but excluding the fourth anniversary and at par beginning on the fourth anniversary. The term loan may be subject to mandatory prepayments and offers to purchase with net cash proceeds of certain issuances of debt, certain asset sales and other dispositions of collateral and upon a change of control.

Senior Secured Second Lien Notes

Our second lien notes are secured second lien obligations and are effectively junior to our current and future secured first lien indebtedness, including indebtedness incurred under our revolving credit facility and our term loan facility, to the extent of the value of the collateral securing such indebtedness, effectively senior to all of our existing and future unsecured indebtedness, including our outstanding senior notes, to the extent of the value of the collateral, and senior to any future subordinated indebtedness that we may incur. We have the option to redeem the second lien notes, in whole or in part, at specified make-whole or redemption prices. Our second lien notes are governed by an indenture containing covenants that may limit our ability and our subsidiaries' ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, consolidate, merge or transfer assets and dispose of certain collateral and use proceeds from dispositions of certain collateral. As a holding company, Chesapeake owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake's obligations under the second lien notes are fully and unconditionally guaranteed, jointly and severally, by certain of our direct and indirect wholly owned subsidiaries.

In December 2015, certain of the existing notes that were exchanged for the second lien notes were accounted for as a troubled debt restructuring (TDR). For the exchanges classified as a TDR, if the future undiscounted cash flows of the newly issued debt are less than the net carrying value of the original debt, a gain is recorded for the difference and the carrying value of the newly issued debt is adjusted to the future undiscounted cash flow amount and no future interest expense is recorded. All future interest payments on the newly issued debt reduce the carrying value.

Senior Notes, Contingent Convertible Senior Notes and Convertible Senior Notes

Our obligations under our outstanding senior notes and convertible senior notes are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries on a senior unsecured basis. Our non-guarantor subsidiaries are minor and, as such, we have not included condensed consolidating financial information in the notes to our condensed consolidated financial statements.

We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense through the first demand repurchase date, as applicable, at the interest rate of similar nonconvertible debt at the time of issuance. The applicable rates for our 2.5% Contingent Convertible Senior Notes due 2037, our 2.25% Contingent Convertible Senior Notes due 2038 and our 5.5% Convertible Senior Notes due 2026 are 8.0%, 8.0% and 11.5%, respectively.

During the Current Quarter, we issued in a private placement $750 million aggregate principal amount of unsecured 8.00% Senior Notes due 2027 at par for net proceeds of approximately $742 million. Some or all of the notes may be redeemed at any time prior to June 15, 2022, subject to a make-whole premium. We also may redeem some or all of the notes at any time on or after June 15, 2022, at the applicable redemption price in accordance with the terms of the notes and the indenture and supplemental indenture governing the notes. In addition, subject to certain conditions, we may redeem up to 35% of the aggregate principal amount of the notes at any time prior to June 15, 2020, at a price equal to 108% of the principal amount of the notes to be redeemed using the net proceeds of certain equity offerings.

In the Current Period, we retired $1.604 billion principal amount of our outstanding senior notes, senior secured second lien notes and contingent convertible notes through purchases in the open market, tender offers or repayment upon maturity for $1.746 billion. Included in these retirements is the maturity of our 6.25% Euro-denominated Senior Notes due 2017, which were carried at $258 million based on the December 31, 2016 exchange rate of $1.0517 to €1.00 and the corresponding cross currency swap. See Foreign Currency Derivatives in Note 8 for further information. For the open market repurchases and tender offers, we recorded aggregate gains of approximately $191 million and $184 million in the Current Quarter and the Current Period, respectively.

In the Prior Period, we retired $558 million principal amount of our outstanding senior notes and contingent convertible senior notes through purchases in the open market or repayment upon maturity for $472 million. Additionally, we privately negotiated an exchange of approximately $577 million principal amount of our outstanding senior notes and contingent convertible senior notes for 109,351,707 common shares. We recorded an aggregate gain of approximately $168 million associated with these repurchases and exchanges, including $68 million in the Prior Quarter.

Revolving Credit Facility

We have a senior secured revolving credit facility currently subject to a $3.8 billion borrowing base that matures in December 2019. Our borrowing base may be reduced in certain circumstances, including if we dispose of a certain percentage of the value of collateral securing the revolving credit facility. As of June 30, 2017, we had outstanding borrowings of $575 million under the revolving credit facility and had used $100 million of the revolving credit facility for various letters of credit. The terms of the revolving credit facility include covenants limiting, among other things, our ability 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. We were in compliance with all applicable financial covenants under the agreement as of June 30, 2017. As of June 30, 2017, we were able to borrow the full availability under the revolving credit facility.

On June 15, 2017, we completed a scheduled borrowing base redetermination review and our lenders reaffirmed our $3.8 billion borrowing base. Our next scheduled borrowing base redetermination is scheduled for the second quarter of 2018. On May 19, 2017, we entered into the fourth amendment to our revolving credit facility. Among other things, the amendment removed the requirement that we must concurrently prepay, repurchase or redeem or otherwise defease at least an equal amount of other borrowed money indebtedness with a stated maturity prior to December 15, 2019, if we optionally prepay, repurchase or redeem or otherwise defease other borrowed money indebtedness with a stated maturity after December 15, 2019.

During 2016, we entered into the third amendment to our revolving credit facility. The amendment reaffirmed our borrowing base and granted temporary financial covenant relief, with the revolving credit facility’s existing first lien secured leverage ratio and net debt to capitalization ratio suspended until September 30, 2017 (at which point the maximum first lien secured leverage ratio will be 3.50 to 1.0 through the period ending December 31, 2017 and 3.00 to 1.0 thereafter and the maximum net debt to capitalization ratio for each period will be 65%) and the interest coverage ratio maintenance covenant reduced as noted below. In addition, we agreed to grant liens and security interests on a majority of our assets, as well as maintain a minimum liquidity amount (defined as cash and cash equivalents and availability under our revolving credit facility) of $500 million until the suspension of the existing maintenance covenants ends.

The third amendment reduced the interest coverage ratio to 0.70 to 1.0 for the second quarter of 2017, after which it will increase to 1.2 to 1.0 for the third quarter of 2017 and 1.25 to 1.0 thereafter. The amendment also gives us the ability to incur up to $2.5 billion of first lien indebtedness secured on a pari passu basis with the existing obligations under the credit agreement, subject to a position in the collateral proceeds waterfall in favor of the revolving lenders and affiliated hedge providers and the other limitations on junior lien debt set forth in the credit agreement. After taking

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into account the term loan, the amount of additional first lien indebtedness permitted by the revolving credit facility is $1.0 billion.

Fair Value of Debt

We estimate the fair value of our senior notes based on the market value of our publicly traded debt as determined based on the yield of our senior notes (Level 1). The fair value of all other debt is based on a market approach using estimates provided by an independent investment financial data services firm (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	June 30, 2017		December 31, 2016	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$3	$3	$503	$ 511
Long-term debt (Level 1)	$2,876	$2,791	$3,271	$ 3,216
Long-term debt (Level 2)	$6,972	$6,890	$6,664	$ 6,654

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 accrued 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.

Regulatory and Related 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 natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company’s royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.

In addition, the Company received a DOJ subpoena and a voluntary document request from the SEC seeking information on our accounting methodology for the acquisition and classification of oil and natural gas properties and related matters. On October 4, 2016, a securities class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and certain current directors and officers of the Company alleging, among other things, violations of federal securities laws for purported misstatements in the Company’s SEC filings and other public disclosures regarding the Company’s accounting for the acquisition and classification of oil and natural gas properties. On June 20, 2017, the DOJ orally advised Chesapeake that it was closing its investigation, and on July 17, 2017, the SEC indicated by letter that it had concluded its investigation and that it did not intend to recommend an enforcement action on the matter. The related securities class action was dismissed on March 14, 2017.

On July 10, 2017, Chesapeake, its Benefits Committee, its Investment Committee and certain employees were named as defendants in a purported Employee Retirement Income Security Act of 1974 (ERISA) class action filed in the

United States District Court for the Western District of Oklahoma (the “ERISA Lawsuit”). The ERISA Lawsuit alleges violations of Sections 404, 405, 409 and 502 of ERISA with respect to the Company’s common stock held in its Savings and Incentive Stock Bonus Plan (the “Plan”). The plaintiffs seek to represent a class of persons who were participants in the Plan after June 1, 2014. The plaintiffs also seek damages, imposition of a constructive trust and other relief, including attorneys’ fees, based on allegations that the defendants breached their fiduciary duties by continuing to allow the Company’s common stock to remain as an investment option under the Plan during the class period.

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.

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. Plaintiffs have varying royalty provisions in their respective leases, oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. 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, Texas, Pennsylvania, Ohio, Oklahoma, Kentucky, 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.

Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. These lawsuits, organized for pre-trial proceedings with respect to the Barnett Shale and Eagle Ford Shale, respectively, generally allege that Chesapeake underpaid royalties by making improper deductions, using incorrect production volumes and similar theories. Chesapeake expects that additional lawsuits will continue to be pursued and that new plaintiffs will file other lawsuits making similar allegations.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit includes other UTPCPL claims and antitrust claims, including that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and permanent injunction from further violations of the UTPCPL.

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 for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources.

We believe losses are reasonably possible in certain of the 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.

The Company is also defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits were filed in the U.S. District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the U.S. District Court of Kansas, in each case against the Company and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney's fees, costs and interest, as well as enjoinment from adopting practices or plans that would restrain competition in a similar manner as alleged in the lawsuits.

Other Matters

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, programs, 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 oil, natural gas and NGL 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 as obligations in the accompanying condensed consolidated balance sheets.

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, are presented below.

	June 30, 2017
	($ in millions)
2017	$ 664
2018	1,096
2019	1,061
2020	990
2021	894
2022 – 2035	5,213
Total	$ 9,918

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 vary with the applicable agreement.

Drilling Contracts

We have contracts with various drilling contractors to utilize drilling services at market-based pricing. These commitments are not recorded as obligations in the accompanying condensed consolidated balance sheets. As of June 30, 2017, the aggregate undiscounted minimum future payments under these drilling service commitments were approximately $49 million.

Oil, Natural Gas and NGL Purchase Commitments

We commit to purchase oil, natural gas and NGL from other owners in the properties we operate, including owners associated with our volumetric production payment (VPP) transactions. Production purchases under these arrangements are based on market prices at the time of production, and the purchased oil, natural gas and NGL are resold at market prices. See Volumetric Production Payments in Note 9 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our Utica Shale joint venture agreements with Total S.A., we are obligated to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage maintenance level is met as of the December 31, 2017 measurement date.

Other Commitments

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 acquisitions and 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 natural 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 Volumetric Production Payments in 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, 2017 and December 31, 2016 are detailed below.

	June 30, 2017	December 31, 2016
	($ in millions)	
Revenues and royalties due others	$481	$ 543
Accrued drilling and production costs	259	169
Joint interest prepayments received	72	71
Accrued compensation and benefits	158	239
Other accrued taxes	58	32
Bank of New York Mellon legal accrual[a]	—	440
Other	269	304
Total other current liabilities	$1,297	$ 1,798

(a) In the Current Quarter, we received notice from the U.S. Supreme Court that it would not review our appeal of the decision by the U.S. District Court for the Southern District of New York regarding the redemption at par value of our 6.775% Senior Notes due 2019. As a result of the decision, we paid $441 million with cash on hand and borrowings under the credit facility, and the related supersedeas bond was released.

Other long-term liabilities as of June 30, 2017 and December 31, 2016 are detailed below.

	June 30, 2017	December 31, 2016
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$164	$ 160
Unrecognized tax benefits	98	97
Other	112	126
Total other long-term liabilities	$374	$ 383

(a) The CHK Utica L.L.C. investors' right to receive proportionately a 3% overriding royalty interest (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. The liability represents the obligation to deliver future ORRIs. As of June 30, 2017, and December 31, 2016, approximately $30 million and $43 million of the total ORRI obligations are recorded in other current liabilities.

6. Equity

Common Stock

A summary of the changes in our common shares issued for the Current Period and the Prior Period is detailed below.

	Six Months Ended June 30, 2017	2016
	(in thousands)	
Shares issued as of January 1	896,279	664,796
Exchange of convertible notes	—	55,428
Exchange of senior notes	—	53,924
Exchange/conversion of preferred stock	9,966	1,021
Restricted stock issuances (net of forfeitures and cancellations)	1,732	1,529
Shares issued as of June 30	907,977	776,698

During the Current Quarter, our shareholders approved an amendment to our certificate of incorporation to increase our authorized common stock to 2,000,000,000 shares, par value $0.01 per share.

Preferred Stock

Outstanding shares of our preferred stock for the Current Period and the Prior Period are detailed below.

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2017	843	476	2,559	1,962
Preferred stock conversions/exchanges[a]	(73)	(13)	—	(151)
Shares outstanding as of June 30, 2017	770	463	2,559	1,811
Shares outstanding as of January 1, 2016	1,497	1,100	2,559	2,096
Preferred stock conversions/exchanges[b]	(25)	(1)	—	—
Shares outstanding as of June 30, 2016	1,472	1,099	2,559	2,096

(a) In the Current Period, holders of our 5.75% Cumulative Convertible Preferred Stock exchanged 72,600 shares into 7,442,156 shares of common stock, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock exchanged 12,500 shares into 1,205,923 shares of common stock and holders of our 5.00% (Series 2005B) Cumulative Convertible Preferred Stock exchanged 150,948 shares into 1,317,756 shares of common stock. In connection with the exchanges, we recognized a loss equal to the excess of the fair value of all common stock issued in exchange for the preferred stock over the fair value of the common stock issuable pursuant to the original terms of the preferred stock. The loss of $41 million is reflected as a reduction to net income available to common stockholders for the purpose of calculating earnings per common share.

(b) In the Prior Period, holders of our 5.75% Cumulative Convertible Preferred Stock converted 24,601 shares into 975,488 shares of common stock and holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock converted 1,201 shares into 46,018 shares of common stock.

Dividends

Dividends declared on our 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, payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

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

In the Prior Period, we suspended dividend payments on our convertible preferred stock to provide additional liquidity in the depressed commodity price environment. In the Current Period, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock and paid our dividends in arrears.

Accumulated Other Comprehensive Income (Loss)

For the Current Period and the Prior Period, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below.

	Six Months Ended June 30,	
	2017	2016
	($ in millions)	
Balance, as of January 1	$(96)	$(99)
Other comprehensive income (loss) before reclassifications	4	(19)
Amounts reclassified from accumulated other comprehensive income	17	14
Net other comprehensive income (loss)	21	(5)
Balance, as of June 30	$(75)	$(104)

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, net losses on cash flow hedges for commodity contracts reclassified from accumulated other comprehensive income (loss), net of tax, to oil, natural gas and NGL revenues in the condensed consolidated statements of operations were $7 million, $10 million, $17 million and $14 million, respectively.

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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 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 units to employees and non-employee directors. 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, 2017	9,092	$ 11.39
Granted	9,457	$ 5.46
Vested	(3,547)	$ 14.33
Forfeited	(737)	$ 9.38
Unvested restricted stock as of June 30, 2017	14,265	$ 6.83

The aggregate intrinsic value of restricted stock that vested during the Current Period was approximately $21 million based on the stock price at the time of vesting.

As of June 30, 2017, there was approximately $70 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 2.09 years.

Stock Options. In the Current Period and the Prior Period, we granted members of management stock options that vest ratably over a three-year period. 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 expire seven to 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. 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	6.0	
Volatility	62.42	%
Risk-free interest rate	2.17	%
Dividend yield	—	%

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The following table provides information related to stock option activity in 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 as of January 1, 2017	8,593	$ 11.88	7.22	$ 14
Granted	9,226	$ 5.45		
Exercised	—	$ —		$ —
Expired	(277)	$ 18.74		
Forfeited	(806)	$ 10.45		
Outstanding as of June 30, 2017	16,736	$ 8.29	8.18	$ 5
Exercisable as of June 30, 2017	4,738	$ 15.37	5.44	$ 2

(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, 2017, there was $29 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.50 years.

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,	
	2017	2016	2017	2016
	($ in millions)			
General and administrative expenses	$ 12	$ 10	$ 20	$ 18
Oil and natural gas properties	3	5	7	9
Oil, natural gas and NGL production expenses	4	3	7	6
Marketing, gathering and compression expenses	—	—	—	1
Total restricted stock and stock option compensation	$ 19	$ 18	$ 34	$ 34

Liability-Classified Awards

Performance Share Units. We have granted PSUs to senior management that vest ratably over a three-year term 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 levels.

For PSUs granted, the TSR component can range from 0% to 100% and the operational component can range from 0% to 100%, resulting in a maximum payout of 200%. Compensation expense associated with PSU grants is recognized over the service period based on the graded-vesting method. The value of the PSU awards at the end of each reporting period is dependent upon the Company’s estimates of the underlying performance measures. The payout percentage for all PSU grants is capped at 100% if the Company’s absolute TSR is less than zero. The Company utilized a Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs.

Volatility	83.94	%
Risk-free interest rate	1.47	%
Dividend yield for value of awards	—	%

The following table presents a summary of our 2017, 2016 and 2015 PSU awards.

	Units	Grant Date Fair Value	June 30, 2017 Fair Value	June 30, 2017 Vested Liability
		($ in millions)	($ in millions)	
2017 Awards:				
Payable 2020	1,217,774	$ 8	$ 7	$ 2
2016 Awards:				
Payable 2019	2,348,893	$ 10	$ 14	$ 10
2015 Awards:				
Payable 2018	629,694	$ 13	$ 2	$ 1

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, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	($ in millions)			
General and administrative expenses	$ —	$ 1	$ (2)	$ 3
Restructuring and other termination costs	—	—	—	1
Total PSU compensation	$ —	$ 1	$ (2)	$ 4

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8. Derivative and Hedging Activities

Chesapeake uses 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, when applicable, to mitigate a portion of its exposure to 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. None of our derivative instruments were designated for hedge accounting as of June 30, 2017 and December 31, 2016.

Oil, Natural Gas and NGL Derivatives

As of June 30, 2017 and December 31, 2016, our oil, natural gas and NGL 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.
- 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.
- 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.
- Basis Protection Swaps: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

The estimated fair values of our oil, natural gas and NGL derivative instrument assets (liabilities) as of June 30, 2017 and December 31, 2016 are provided below.

	June 30, 2017		December 31, 2016	
	Volume	Fair Value	Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	13	$ 45	23	$ (140)
Call options	3	—	5	(1)
Total oil	16	45	28	(141)
Natural gas (tbtu):				
Fixed-price swaps	704	28	719	(349)
Collars	71	10	60	(9)
Call options	90	—	114	—
Basis protection swaps	13	(2)	31	(5)
Total natural gas	878	36	924	(363)
NGL (mmgal):				
Fixed-price swaps	—	—	53	—
Total estimated fair value		$ 81		$ (504)

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).

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Interest Rate Derivatives

As of June 30, 2017 and December 31, 2016, there were no interest rate derivatives outstanding.

We have terminated fair value hedges related to certain of our 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 three years, we will recognize $2 million in net gains related to these transactions.

Foreign Currency Derivatives

During the Current Period, both our 6.25% Euro-denominated Senior Notes due 2017 and cross currency swaps for the same principal amount matured. Upon maturity of the notes, the counterparties paid us €246 million and we paid the counterparties $327 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. The swaps were designated as cash flow hedges and, because they were 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 did not impact earnings. The fair values of the cross currency swaps were recorded on the condensed consolidated balance sheet as a liability of $73 million as of December 31, 2016.

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. The bifurcated derivative is measured at fair value on a quarterly basis and resulted in an unrealized loss of $37 million and $17 million in the Prior Quarter and the Prior Period, respectively. Both settlements and mark-to-market gains (losses) are included in marketing, gathering and compression revenues in our condensed consolidated statements of operations. This supply contract was sold in the third quarter of 2016.

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Effect of Derivative Instruments – Condensed Consolidated Balance Sheets
The following table presents the fair value and location of each classification of derivative instrument included in the condensed consolidated balance sheets as of June 30, 2017 and December 31, 2016 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in the Condensed Consolidated Balance Sheets	Net Fair Value Presented in the Condensed Consolidated Balance Sheet
	($ in millions)		
As of June 30, 2017			
Commodity Contracts:			
Short-term derivative asset	$92	$ (21)	$ 71
Short-term derivative liability	(24)	21	(3)
Long-term derivative asset	14	—	14
Long-term derivative liability	(1)	—	(1)
Total commodity contracts	81	—	81
Total derivatives	$81	$ —	$ 81
As of December 31, 2016			
Commodity Contracts:			
Short-term derivative asset	$1	$ (1)	$ —
Short-term derivative liability	(490)	1	(489)
Long-term derivative liability	(15)	—	(15)
Total commodity contracts	(504)	—	(504)
Foreign Currency Contracts:[a]			
Short-term derivative liability	(73)	—	(73)
Total foreign currency contracts	(73)	—	(73)
Total derivatives	$(577)	$ —	$ (577)

(a) Designated as cash flow hedging instruments.

As of June 30, 2017 and December 31, 2016, we did not have any cash collateral balances for these derivatives.

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Effect of Derivative Instruments – Condensed Consolidated Statements of Operations
The components of oil, natural gas and NGL revenues 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,	
	2017	2016	2017	2016
	($ in millions)			
Oil, natural gas and NGL revenues	$1,079	$884	$2,226	$1,696
Gains (losses) on undesignated oil, natural gas and NGL derivatives	207	(438)	539	(246)
Losses on terminated cash flow hedges	(7)	(6)	(17)	(17)
Total oil, natural gas and NGL revenues	$1,279	$440	$2,748	$1,433

The components of marketing, gathering and compression revenues 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,	
	2017	2016	2017	2016
	($ in millions)			
Marketing, gathering and compression revenues	$1,002	$1,219	$2,286	$2,159
Losses on undesignated supply contract derivatives	—	(37)	—	(17)
Total marketing, gathering and compression revenues	$1,002	$1,182	$2,286	$2,142

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,	
	2017	2016	2017	2016
	($ in millions)			
Interest expense on senior notes	$136	$148	$272	$305
Interest expense on term loan	32	—	64	—
Amortization of loan discount, issuance costs and other	6	7	15	18
Amortization of premium associated with troubled debt restructuring	(42)	(41)	(83)	(83)
Interest expense on revolving credit facilities	8	12	17	17
Gains on terminated fair value hedges	—	(1)	—	(1)
(Gains) losses on undesignated interest rate derivatives	—	—	1	—
Capitalized interest	(47)	(63)	(98)	(132)
Total interest expense	$93	$62	$188	$124

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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,			
	2017		2016	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(139)	$(82)	$(156)	$(99)
Net change in fair value	—	—	(13)	(15)
Losses reclassified to income	7	7	6	10
Balance, end of period	$(132)	$(75)	$(163)	$(104)

	Six Months Ended June 30,			
	2017		2016	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(153)	$(96)	$(160)	$(99)
Net change in fair value	4	4	(20)	(19)
Losses reclassified to income	17	17	17	14
Balance, end of period	$(132)	$(75)	$(163)	$(104)

The accumulated other comprehensive loss, as of June 30, 2017, represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. 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, 2017, 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

Our derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of June 30, 2017, our oil, natural gas and NGL derivative instruments were spread among 10 counterparties.

Hedging Arrangements

Certain of our hedging arrangements are with counterparties that are also lenders (or affiliates of lenders) under our revolving credit facility. The contracts entered into with these counterparties are secured by the same collateral that secures our revolving credit facility, which allows us to reduce any letters of credit posted as security with those counterparties. In addition, with other counterparties we enter into bilateral hedging agreements. The counterparties' and our obligations under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds.

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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, natural gas and NGL 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, NGL 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, 2017 and December 31, 2016:

	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, 2017				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 97	$ 10	$ 107
Commodity liabilities	—	(26)	—	(26)
Total derivatives	$ —	$ 71	$ 10	$ 81
As of December 31, 2016				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 1	$ —	$ 1
Commodity liabilities	—	(495)	(10)	(505)
Foreign currency liabilities	—	(73)	—	(73)
Total derivatives	$ —	$ (567)	$ (10)	$ (577)

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)	
Balance, as of January 1, 2017	$(10)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	19	—
Total purchases, issuances, sales and settlements:		
Settlements	1	—
Balance, as of June 30, 2017	$10	$ —
Balance, as of January 1, 2016	$(91)	$ 297
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	(8)	13
Total purchases, issuances, sales and settlements:		
Settlements	28	(30)
Balance, as of June 30, 2016	$(71)	$ 280

(a)

	Oil, Natural Gas and NGL Sales		Marketing, Gathering and Compression Revenue	
	2017	2016	2017	2016
	($ in millions)			
Total gains (losses) included in earnings for the period	$19	$(8)	$ —	$ (17)
Change in unrealized gains (losses) related to assets still held at reporting date	$12	$(20)	$ —	$ (17)

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 natural gas, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts, which is based on an estimate derived from option models. 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, 2017:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value June 30, 2017 ($ in millions)
Oil trades	Oil price volatility curves	19.14% – 26.38%	24.85%	$ —
Natural gas trades	Natural gas price volatility curves	20.78% – 56.51%	43.10%	$ 10

9. Oil and Natural Gas Property Transactions

Under full cost accounting rules, we accounted for the sales of oil and natural gas properties discussed below as adjustments to capitalized costs, with no recognition of gain or loss as the sales did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves.

In the Current Period, we sold portions of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $915 million, subject to certain customary closing adjustments. Included in the sales were approximately 119,500 net acres and interests in 576 wells that were producing approximately 80 mmcf of gas per day at the time of closing.

Also in the Current Quarter and the Current Period, we received proceeds of $63 million and $83 million, respectively, for the sale of other oil and natural gas properties.

In the Prior Quarter and the Prior Period, we sold certain of our noncore oil and natural gas properties for net proceeds of approximately $833 million and $964 million, respectively, after post-closing adjustments. In conjunction with certain of these sales, we purchased oil and natural gas interests previously sold to third parties in connection with four of our VPP transactions for approximately $259 million. A majority of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas.

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 non-recourse 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 to each of the respective VPP buyers hedges that 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. Future costs 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, 2017, we had the following VPP outstanding:

VPP #	Date of VPP	Location	Proceeds	Volume Sold Oil	Natural Gas	NGL	Total
			($ in millions)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	May 2011	Mid-Continent	$ 853	1.7	138	4.8	177

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, 2017				Three Months Ended June 30, 2016			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	—	—	—	—	42.0	1.2	146.0	2.3
9	35.2	3.0	81.3	3.7	38.5	3.3	87.6	4.1
4[(a)]	—	—	—	—	9.9	1.9	—	2.0
3[(a)]	—	—	—	—	—	1.0	—	1.0
2[(a)]	—	—	—	—	—	0.6	—	0.6
1[(a)]	—	—	—	—	—	3.1	—	3.1
	35.2	3.0	81.3	3.7	90.4	11.1	233.6	13.1

	Six Months Ended June 30, 2017				Six Months Ended June 30, 2016			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	—	—	—	—	108.0	3.0	368.7	5.8
9	71.1	6.1	164.1	7.5	77.9	6.7	176.9	8.2
4[(a)]	—	—	—	—	20.0	3.8	—	3.9
3[(a)]	—	—	—	—	—	2.5	—	2.5
2[(a)]	—	—	—	—	—	1.5	—	1.5
1[(a)]	—	—	—	—	—	6.4	—	6.4
	71.1	6.1	164.1	7.5	205.9	23.9	545.6	28.3

(a) In connection with certain asset divestitures in 2016, we purchased the remaining oil and natural gas interests previously sold in connection with VPP #10, VPP #4, VPP #3, VPP #2 and VPP #1. A majority of the oil and natural gas interests purchased were subsequently sold to the buyers of the assets.

The volumes remaining to be delivered on behalf of our VPP buyers as of June 30, 2017 were as follows:

VPP #	Term Remaining	Volume Remaining as of June 30, 2017 Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	44	0.4	39.7	1.1	48.7

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10. Variable Interest Entities

We consolidate the activities of VIEs for which we are the primary beneficiary. 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 (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 and because the royalty interest owners, other than Chesapeake, do not have the ability to exercise substantial liquidation rights. Our ownership in the Trust and our previous obligations under the development agreement constitute variable interests. On June 30 2017, the Trust's subordinated units, all of which were held by Chesapeake, converted to common units. We continue to consolidate the activities of the Trust as 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 operation of the majority of the producing wells and the completed development wells, and (ii) we have the obligation to absorb losses that potentially could 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. As of June 30, 2017 and December 31, 2016, we had $254 million and $257 million, respectively, of noncontrolling interests on our condensed consolidated balance sheets attributable to the Trust. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we had $1 million, a nominal amount, $2 million and a nominal amount, respectively, of net income attributable to the Trust's noncontrolling interests recorded in our condensed consolidated statements of operations.

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. In consolidation, as of June 30, 2017, $1 million of cash and cash equivalents, $488 million of proved oil and natural gas properties, $459 million of accumulated depreciation, depletion and amortization and $4 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.

11. Impairments

Impairments of Oil and Natural Gas Properties

Our proved 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 Prior Quarter and the Prior 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 $1.070 billion and $2.067 billion, respectively.

Impairments of Fixed Assets and Other

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	($ in millions)			
Natural gas compressors	$—	$ —	$—	$ 20
Buildings and land	2	—	2	7
Other	24	6	415	17
Total impairments of fixed assets and other	$26	$ 6	$417	$ 44

Other. In the Current Quarter and the Current Period, we terminated future natural gas transportation commitments related to divested assets for cash payments of $23 million and $126 million, respectively. In the Current Period, we also paid $290 million to assign an oil transportation agreement to a third party.

Nonrecurring Fair Value Measurements. Fair value measurements for certain of the impairments 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.

12. 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 taxable income is generated, to determine whether a valuation allowance is required. The 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 our estimated operating results for the subsequent quarters, we project being in a net deferred tax asset position as of December 31, 2017. 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, 2017. The 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 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. A valuation allowance was recorded against our net deferred tax asset as of December 31, 2016 and June 30, 2017.

13. Fair Value Measurements

Recurring Fair Value Measurements

Other Current Assets. Assets related to Chesapeake's deferred compensation plan are included in other current assets. The fair value of these assets is determined using quoted market prices as they consist of exchange-traded securities.

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

Financial Assets (Liabilities). The following table provides fair value measurement information for the above-noted financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2017 and December 31, 2016:

	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, 2017				
Financial Assets (Liabilities):				
Other current assets	$56	$ —	$ —	$ 56
Other current liabilities	(56)	—	—	(56)
Total	$—	$ —	$ —	$ —
As of December 31, 2016				
Financial Assets (Liabilities):				
Other current assets	$49	$ —	$ —	$ 49
Other current liabilities	(51)	—	—	(51)
Total	$(2)	$ —	$ —	$ (2)

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

See Note 3 for information regarding fair value measurement of our debt instruments. See Note 8 for information regarding fair value measurement of our derivatives.

Nonrecurring Fair Value Measurements

See Note 11 regarding nonrecurring fair value measurements.

14. Segment Information

As of June 30, 2017, 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.

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 $1.050 billion, $848 million, $2.170 billion and $1.631 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

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

	Exploration and Production	Marketing, Gathering and Compression	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)				
Three Months Ended June 30, 2017					
Revenues	$1,279	$ 2,052	$—	$ (1,050)	$ 2,281
Intersegment revenues	—	(1,050)	—	1,050	—
Total Revenues	$1,279	$ 1,002	$—	$ —	$ 2,281
Income (Loss) Before Income Taxes	$541	$ (61)	$(12)	$ 28	$ 496
Three Months Ended June 30, 2016					
Revenues	$440	$ 2,030	$—	$ (848)	$ 1,622
Intersegment revenues	—	(848)	—	848	—
Total Revenues	$440	$ 1,182	$—	$ —	$ 1,622
Income (Loss) Before Income Taxes (as previously reported)	$(1,755)	$ (44)	$(8)	$ 57	$ (1,750)
Income (Loss) Before Income Taxes (as revised)	$(1,781)	$ (44)	$(8)	$ 57	$ (1,776)
Six Months Ended June 30, 2017					
Revenues	$2,748	$ 4,456	$—	$ (2,170)	$ 5,034
Intersegment revenues	—	(2,170)	—	2,170	—
Total Revenues	$2,748	$ 2,286	$—	$ —	$ 5,034
Income (Loss) Before	$1,108	$ (447)	$(22)	$ (1)	$ 638

Income Taxes

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

	Exploration and Production	Marketing, Gathering and Compression	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)				
Six Months Ended June 30, 2016					
Revenues	$1,433	$ 3,773	$—	$ (1,631)	$ 3,575
Intersegment revenues	—	(1,631)	—	1,631	—
Total Revenues	$1,433	$ 2,142	$—	$ —	$ 3,575
Income (Loss) Before Income Taxes (as previously reported)	$(2,650)	$ (4)	$(17)	$ —	$ (2,671)
Income (Loss) Before Income Taxes (as revised)	$(2,823)	$ (4)	$(17)	$ —	$ (2,844)
As of June 30, 2017					
Total Assets	$10,385	$ 932	$1,014	$ (411)	$ 11,920
As of December 31, 2016					
Total Assets	$11,249	$ 1,118	$1,059	$ (398)	$ 13,028

15. Recently Issued Accounting Standards

In May 2014, the FASB issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration the company expects to receive in the exchange. In March 2016, the FASB issued an update clarifying the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued an update clarifying the identification of performance obligations and licensing implementations guidance. In May 2016, the FASB issued an update clarifying guidance in a few narrow areas and added some practical expedients to the guidance. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017, with early application permitted after December 31, 2016. The standard is required to be adopted using either the full retrospective approach or the modified retrospective approach. While early adoption is permitted, we plan to adopt this new standard in the first quarter of 2018 using the modified retrospective approach. Through June 30, 2017, we have made progress on contract reviews, drafting accounting policies and evaluating the new disclosure requirements. We expect that enhanced disclosures will be required under the new standard. Further analysis is planned in 2017 to complete our evaluation of the impact of the new standard.

In February 2016, the FASB issued updated lease accounting guidance requiring companies to recognize the assets and liabilities for the rights and obligations created by long-term leases of assets on the balance sheet. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. The standard will not apply to our leases of mineral rights. We are continuing to further evaluate the impact of this guidance on our consolidated financial statements and related disclosures.

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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,	
	2017	2016	2017	2016
Net Production:				
Oil (mmbbl)	8	8	16	17
Natural gas (bcf)	209	269	420	546
NGL (mmbbl)	5	7	10	13
Oil equivalent (mmboe)[a]	48	60	96	121
Oil, Natural Gas and NGL Sales ($ in millions):				
Oil sales	$383	$355	$761	$610
Oil derivatives – realized gains (losses)[b]	33	11	44	84
Oil derivatives – unrealized gains (losses)[b]	47	(168)	141	(240)
Total oil sales	463	198	946	454
Natural gas sales	601	440	1,254	923
Natural gas derivatives – realized gains (losses)[b]	(36)	92	(52)	242
Natural gas derivatives – unrealized gains (losses)[b]	156	(365)	387	(335)
Total natural gas sales	721	167	1,589	830
NGL sales	95	89	211	163
NGL derivatives – realized gains (losses)[b]	1	(3)	2	(3)
NGL derivatives – unrealized gains (losses)[b]	(1)	(11)	—	(11)
Total NGL sales	95	75	213	149
Total oil, natural gas and NGL sales	$1,279	$440	$2,748	$1,433
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$47.51	$43.00	$48.83	$35.98
Natural gas ($ per mcf)	$2.88	$1.63	$2.99	$1.69
NGL ($ per bbl)	$18.36	$13.37	$20.99	$12.43
Oil equivalent ($ per boe)	$22.46	$14.76	$23.29	$14.01
Average Sales Price (including realized gains (losses) on derivatives):				
Oil ($ per bbl)	$51.65	$44.31	$51.68	$40.93
Natural gas ($ per mcf)	$2.71	$1.97	$2.87	$2.14
NGL ($ per bbl)	$18.51	$12.88	$21.19	$12.17
Oil equivalent ($ per boe)	$22.42	$16.43	$23.23	$16.68
Other Operating Income ($ in millions):				
Marketing, gathering and compression net margin[c][d]	$(25)	$(25)	$(69)	$(7)

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Expenses ($ per boe):				
Oil, natural gas and NGL production	$2.92	$3.05	$2.88	$3.21
Oil, natural gas and NGL gathering, processing and transportation	$7.44	$8.04	$7.45	$7.96
Production taxes	$0.42	$0.32	$0.45	$0.31
General and administrative	$1.45	$1.02	$1.40	$0.90
Oil, natural gas and NGL depreciation, depletion and amortization	$4.21	$4.64	$4.18	$4.47
Depreciation and amortization of other assets	$0.43	$0.48	$0.44	$0.48
Interest expense[(e)]	$1.92	$1.00	$1.94	$0.99
Interest Expense ($ in millions):				
Interest expense	$93	$63	$187	$125
Interest rate derivatives – realized (gains) losses[(f)]	(1)	(3)	(2)	(6)
Interest rate derivatives – unrealized (gains) losses[(f)]	1	2	3	5
Total interest expense	$93	$62	$188	$124

(a) Oil equivalent is based on six mcf of natural gas to one barrel of oil or one barrel of NGL. This ratio reflects an energy content equivalency and not a price or revenue equivalency.

(b) Realized gains (losses) include the following items: (i) settlements and accruals for 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 (including current period settlements for option premiums and early terminated derivatives) 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 segment.

(d) In the Prior Quarter and the Prior Period, we recorded unrealized losses of $37 million and $17 million, respectively, on the fair value of our supply contract derivative. 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 this instrument.

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

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

Overview

We own interests in approximately 20,500 oil and natural gas wells and produced an average of approximately 528 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, the Anadarko Basin in northwestern Oklahoma and the stacked pay in the Powder River Basin in Wyoming. Our natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas and the Marcellus Shale in the northern Appalachian Basin in Pennsylvania. We also own oil and natural gas marketing and natural gas compression businesses.

Our Strategy

Chesapeake's strategy is to create shareholder value through the development of our significant positions in premier U.S. onshore resource plays. In addition, we continue to focus our financial strategy on reducing debt and improving margins and returns on capital. We apply financial discipline to all aspects of our business with goals of increasing financial and operational flexibility. Our capital program is focused on investments that can improve our cash flow generating ability regardless of the commodity price environment. Our forecasted capital expenditures are higher in 2017 compared to 2016 as we focus on capturing high rate-of-return opportunities in our oil and natural gas portfolio. These opportunities are primarily the result of improved capital and operating efficiencies, including improved well performance. We expect our anticipated production increases in the 2017 second half and into 2018, combined with our cost leadership, to position us with the ability to balance capital expenditures and operating cash flow in 2018. Our substantial inventory of hydrocarbon resources, including our significant undeveloped acreage position in each of our key basins, provides a strong foundation to create future value. Concentrated blocks of undeveloped acreage give us the opportunity to apply best in class well spacing analysis, completion techniques and lateral lengths to maximize capital efficiency. We have greatly improved our capital and operating efficiency metrics over the last several periods and today have a leading cost structure in each of our major operating basins. We believe our cost structure provides a significant competitive advantage in the current commodity price environment and it is our strategy to continue to seek capital and operating efficiencies to grow this advantage. Building on our strong and diverse asset base through increased production and cash flow and further delineating our emerging new development opportunities, we believe that our dedication to financial discipline, the flexibility and efficiency of our capital program and cost structure and our continued focus on safety and environmental stewardship will provide opportunities to create value for Chesapeake and its stakeholders.

Operating Results

Our Current Quarter production of 48 mmboe consisted of 8 mmbbls of oil (17% on an oil equivalent basis), 209 bcf of natural gas (72% on an oil equivalent basis), and 5 mmbbls of NGL (11% on an oil equivalent basis). Our daily production for the Current Quarter averaged approximately 528 mboe, a decrease of 20% from the Prior Quarter. Compared to the Prior Quarter, average daily oil production decreased by 2%, or approximately 2 mbbls per day; average daily natural gas production decreased by 23%, or approximately 667 mmcf per day; and average daily NGL production decreased by 22%, or approximately 16 mbbls per day. Our oil, natural gas and NGL production decreased primarily as a result of the sale of certain of our Mid-Continent and Barnett Shale assets in 2016 and the sale of certain of our Haynesville Shale assets in 2017. Adjusted for asset sales, our total daily production decreased 3% 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) increased approximately $195 million to $1.079 billion in the Current Quarter compared to $884 million in the Prior Quarter, due to increases in the prices received for oil, natural gas and NGL sold, partially offset by the production decreases described above. See Results of Operations below for additional details.

Our Current Period production of 96 mmboe consisted of 16 mmbbls of oil (16% on an oil equivalent basis), 420 bcf of natural gas (73% on an oil equivalent basis), and 10 mmbbls of NGL (11% on an oil equivalent basis). Our daily production for the Current Period averaged approximately 528 mboe, a decrease of 21% from the Prior Period. Compared to the Prior Period, average daily oil production decreased by 8%, or approximately 7 mbbls per day; average daily natural gas production decreased by 23%, or approximately 680 mmcf per day; and average daily NGL production decreased by 23%, or approximately 16 mbbls per day. Our oil, natural gas and NGL production decreased primarily as a result of the sale of certain of our Mid-Continent and Barnett Shale assets in 2016 and the sale of certain of our Haynesville Shale assets in 2017. Adjusted for asset sales, our total daily production decreased 3% 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) increased approximately $530 million to $2.226 billion in the Current Period compared to $1.696 billion in the Prior Period, due to increases in the prices received for oil, natural gas and NGL sold, partially offset by the production decreases described above. See Results of Operations below for additional details.

Capital Expenditures

Our drilling and completion capital expenditures during the Current Quarter were approximately $596 million and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $24 million, for a total of approximately $620 million. In the Current Quarter, we operated an average of 19 rigs, an increase of 10 rigs, or 111%, compared to the Prior Quarter. As a result of higher drilling and completion activity, drilling and completion expenditures increased approximately $259 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 $32 million compared to the Prior Quarter.

Our capitalized interest was approximately $47 million and $63 million in the Current Quarter and the Prior Quarter, respectively. The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. Including capitalized interest, total capital investments were approximately $667 million in the Current Quarter compared to $456 million for the Prior Quarter, an increase of 46%.

Our drilling and completion capital expenditures during the Current Period were approximately $1.102 billion and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $43 million, for a total of approximately $1.145 billion. In the Current Period, we operated an average of 18 rigs, an increase of nine rigs, or 100%, compared to the Prior Period. As a result of higher drilling and completion activity, drilling and completion expenditures increased approximately $484 million in the Current Period compared to the Prior Period. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $27 million compared to the Prior Period.

Our capitalized interest was approximately $98 million and $132 million in the Current Period and the Prior Period, respectively. The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. Including capitalized interest, total capital investments were approximately $1.243 billion in the Current Period compared to $820 million for the Prior Period, an increase of 52%.

Based on planned activity levels for the remainder of 2017, we project that 2017 capital expenditures for drilling and completions, leasehold, geological and geophysical and other property and equipment will be $2.1 – $2.5 billion, inclusive of capitalized interest, as compared to $1.7 billion of capital expenditures in 2016. See Liquidity and Capital Resources for additional information on how we plan to fund our capital budget.

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Strategic Developments

Debt Retirements

In the Current Period, we retired $1.604 billion principal amount of our outstanding senior notes, senior secured second lien notes and contingent convertible notes through purchases in the open market, tender offers or repayment upon maturity for $1.746 billion. Retirements included (i) the maturity of our 6.25% Euro-denominated Senior Notes due 2017 and corresponding cross currency swap, (ii) our tender offer for our 2.5% contingent convertible senior notes due 2037 at the option of the holders of the notes pursuant to the terms of the notes and (iii) our tender offer for up to $750 million aggregate purchase price of certain series of our senior secured second lien notes.

Debt Offering

On June 6, 2017, we issued $750 million aggregate principal amount of unsecured 8.00% Senior Notes due 2027 in a private placement for net proceeds of $742 million.

Preferred Stock Exchanges

In the Current Period, we completed private exchanges of an aggregate of approximately 10.0 million shares of our common stock for (i) 72,600 shares of 5.75% Cumulative Convertible Preferred Stock, (ii) 12,500 shares of 5.75% Cumulative Convertible Preferred Stock (Series A) and (iii) 150,948 shares of 5.00% Cumulative Convertible Preferred Stock (Series 2005B). The preferred stock exchanged represents approximately $100 million of liquidation value. These exchanges eliminated approximately $6 million of annual dividend obligations.

Divestitures

In the Current Period, we sold portions of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $915 million, subject to certain customary closing adjustments. Included in the sales were approximately 119,500 net acres and interests in 576 wells that were producing approximately 80 mmcf of gas per day at the time of closing.

In the Current Period and through August 2, 2017, we have signed or closed approximately $360 million of additional assets divestitures, primarily in our Mid-Continent area.

Gathering, Processing and Transportation Agreements

In the Current Quarter and the Current Period, we terminated future natural gas transportation commitments related to divested assets for cash payments of $23 million and $126 million, respectively. In the Current Period, we also paid $290 million to assign an oil transportation agreement to a third party.

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Liquidity and Capital Resources
Liquidity Overview
Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and NGL we sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been very volatile, and may be subject to wide fluctuations in the future. The substantial decline in oil, natural gas and NGL prices from 2014 levels has negatively affected the amount of cash we generate and have available for capital expenditures and debt service. A substantial or extended decline in oil, natural gas and NGL prices could have a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we may economically produce. Other risks and uncertainties that could affect our liquidity include, but are not limited to, counterparty credit risk for our receivables, access to capital markets, regulatory risks and our ability to meet financial ratios and covenants in our financing agreements.
As of June 30, 2017, we had a cash balance of $13 million compared to $882 million as of December 31, 2016, and we had a net working capital deficit of $911 million, compared to a net working capital deficit of $1.506 billion as of December 31, 2016. Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures, meet our debt service requirements and fund our other commitments and obligations for the next 12 months. As of June 30, 2017, we had $3.110 billion of borrowing capacity available under our revolving credit facility, with outstanding borrowings of $575 million and $100 million utilized for various letters of credit. 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 our debt obligations, including principal and carrying amounts of our notes.
In the Current Period and through August 2, 2017, we took the following measures to improve our near-term liquidity:

- issued $750 million aggregate principal amount of unsecured 8.00% Senior Notes due 2027 and used the proceeds to repurchase a portion of our senior secured second lien notes;
- reaffirmed the borrowing base on our revolving credit facility at $3.8 billon;
- exchanged approximately 10.0 million shares of common stock for approximately $100 million of liquidation value of our preferred stock, eliminating approximately $6 million of annual dividend obligations; and
- signed or closed on approximately $1.3 billion of asset divestitures that did not fit our strategic priorities.

Even though we have taken measures, as outlined above, to mitigate the liquidity concerns facing us for the next 12 months, there can be no assurance that these measures will satisfy our needs. We may continue to access the capital markets or otherwise incur debt to refinance a portion of our outstanding indebtedness and improve our liquidity.
As operator of a substantial portion of our oil and natural gas properties under development, we have significant control and flexibility over the timing and execution of our development plan, enabling us to reduce our capital spending as needed. Our forecasted 2017 capital expenditures, inclusive of capitalized interest, are $2.1 – $2.5 billion compared to our 2016 capital spending level of $1.7 billion. We had liquidity (calculated as cash on hand and availability under our revolving credit facility), of approximately $3.1 billion as of July 31, 2017. We expect to generate additional liquidity with proceeds from future sales of assets that we determine do not fit our strategic priorities. Management continues to review operational plans for the remainder of 2017 and beyond, which could result in changes to projected capital expenditures and projected 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.

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Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, processing, transportation and hedging agreements. As of July 31, 2017, we have received requests and posted approximately $133 million in collateral under such arrangements. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $480 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business relationships with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business arrangements and by offsetting amounts that the counterparty owes us. Any posting of collateral consisting of cash or letters of credit reduces availability under our revolving credit facility and negatively impacts our liquidity.

In the Current Period, we repurchased $1.604 billion principal amount of outstanding debt in the open market and through tender offers and exchanged approximately 10.0 million shares of common stock for approximately $100 million of liquidation value of our outstanding preferred stock. Pursuant to the provisions of our 2.5% Contingent Convertible Senior Notes due 2037, we repurchased $14 million of the outstanding notes in the Current Quarter. In July 2017, we redeemed our remaining 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037 for an aggregate repurchase price of $3 million. We may continue to use a combination of cash, borrowings and issuances of our common stock or other securities to retire our outstanding debt and preferred stock through privately negotiated transactions, open market repurchases, redemptions, tender offers or otherwise, but we are under no obligation to do so.

To add more certainty to our future estimated cash flows by mitigating our downside exposure to lower commodity prices, as of July 31, 2017, we have downside price protection, through open swaps, on approximately 60% of our remaining projected 2017 oil production at an average price of $50.32 per bbl. We also have downside price protection, through open swaps and collars, on approximately 74% of our remaining projected 2017 natural gas production at an average price of $3.09 per mcf, of which 6% is hedged under two-way collar arrangements based on an average bought put NYMEX price of $3.25 per mcf. We also have downside price protection, through open swaps, on approximately 4% of our remaining projected 2017 NGL production at an average price of $0.66 per gallon of propane. In addition, we have downside price protection, through open swaps on 2.7 mmbbls of our 2018 oil production at an average price of $51.78 per bbl and under three-way collar arrangements based on an average bought put NYMEX price of $47.00 per bbl and exposure below an average sold put NYMEX price of $39.15 per bbl. We also have downside price protection, through open swaps and collars on 535 bcf of our 2018 gas production at an average price of $3.09 per mcf.

As highlighted above, we have taken measures to mitigate the liquidity concerns facing us for the remainder of 2017 and beyond, but there can be no assurance that such measures will satisfy our needs. Further, our ability to generate operating cash flow in the current commodity price environment, sell assets, access capital markets or take any other action to improve our liquidity and manage our debt is subject to the risks discussed above and the other risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

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

	Six Months Ended June 30,	
	2017	2016
	($ in millions)	
Cash used in operating activities	$(58)	$(326)
Proceeds from credit facility borrowings, net	575	100
Proceeds from issuance of senior notes, net	742	—
Divestitures of proved and unproved properties	951	964
Sales of other property and equipment	26	70
Total sources of cash and cash equivalents	$2,236	$808

Cash used in operating activities was $58 million in the Current Period compared to $326 million in the Prior Period. The decrease is primarily the result of higher realized prices for the oil, natural gas and NGL we sold, offset by lower volumes of oil, natural gas and NGL sold, the payment related to the litigation on our 6.775% Senior Notes due 2019 and payments for terminations of transportation contracts. 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 further discussion below under Results of Operations.

We currently plan to use cash flow from operations, cash on hand and our revolving credit facility to fund our capital expenditures for the remainder of 2017. We expect to generate additional liquidity with proceeds from future sales of assets that we determine do not fit our strategic priorities. Under our revolving credit facilities, we borrowed $2.551 billion and repaid $1.976 billion in the Current Period and we borrowed $2.477 billion and repaid $2.377 billion in the Prior Period.

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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,	
	2017	2016
	($ in millions)	
Oil and Natural Gas Expenditures:		
Drilling and completion costs	$1,031	$609
Acquisitions of proved and unproved properties	69	302
Interest capitalized on unproved leasehold	93	124
Total oil and natural gas expenditures	1,193	1,035
Other Uses of Cash and Cash Equivalents:		
Cash paid to repurchase debt	1,746	472
Cash paid for title defects	—	69
Additions to other property and equipment	7	25
Dividends paid	137	—
Other	22	28
Total other uses of cash and cash equivalents	1,912	594
Total uses of cash and cash equivalents	$3,105	$1,629

Our drilling and completion costs increased in the Current Period compared to the Prior Period primarily as a result of increased activity. During the Current Period, our average operated rig count was 18 rigs compared to an average operated rig count of nine rigs in the Prior Period and we completed 206 operated wells in the Current Period compared to 185 in the Prior Period.

In the Current Period, we used $1.746 billion of cash to repurchase $1.604 billion principal amount of debt. In the Prior Period, we used $472 million of cash to repurchase $558 million principal amount of debt.

We paid dividends of $137 million on our preferred stock during the Current Period, including $92 million of dividends in arrears that had been suspended throughout 2016. We did not pay dividends on our preferred stock in the Prior Period.

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Term Loan Facility

We have a secured five-year term loan facility in an aggregate principal amount of $1.5 billion. Our obligations under the facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility, second lien notes and senior notes and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 7.50% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 6.50% per annum, subject to a 2.00% ABR floor, at our option. The term loan matures in August 2021 and voluntary prepayments are subject to a make-whole premium prior to the second anniversary of the closing of the term loan, a premium to par of 4.25% from the second anniversary until but excluding the third anniversary, a premium to par of 2.125% from the third anniversary until but excluding the fourth anniversary and at par beginning on the fourth anniversary. The term loan may be subject to mandatory prepayments and offers to purchase with net cash proceeds of certain issuances of debt, certain asset sales and other dispositions of collateral and upon a change of control. 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 term loan facility.

Revolving Credit Facility

We have a senior secured revolving credit facility currently subject to a $3.8 billion borrowing base that matures in December 2019. As of June 30, 2017, we had outstanding borrowings of $575 million under the revolving credit facility and had used $100 million of the revolving credit facility for various letters of credit. See Liquidity Overview above for additional information on our collateral postings. Borrowings under the facility bear interest at a variable rate. We are required to secure our obligations under the facility with liens on certain of our oil and natural gas properties, with the liens to be released upon the satisfaction of specific conditions. The applicable interest rates under the facility fluctuate based on the percentage of the borrowing base used. In the Current Quarter, our borrowing base was reaffirmed at $3.8 billion. Our next borrowing base redetermination is scheduled for the second quarter of 2018. 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 revolving credit facility, as amended. As of June 30, 2017, our interest coverage ratio was approximately 1.78 to 1.00, and we were in compliance with all applicable financial covenants under the credit agreement.

On May 19, 2017, we entered into the fourth amendment to our revolving credit facility. Among other things, the amendment removed the requirement that we must concurrently prepay, repurchase or redeem or otherwise defease at least an equal amount of other borrowed money indebtedness with a stated maturity prior to December 15, 2019, if we optionally prepay, repurchase or redeem or otherwise defease other borrowed money indebtedness with a stated maturity after December 15, 2019.

Hedging Arrangements

Certain of our hedging arrangements are with counterparties that are also lenders (or affiliates of lenders) under our revolving credit facility. The contracts entered into with these counterparties are secured by the same collateral that secures our revolving credit facility which allows us to reduce any letters of credit posted as security with those counterparties. In addition, with other counterparties we enter into bilateral hedging agreements. The counterparties' and our obligations under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds.

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Senior Note Obligations

Our senior note obligations consisted of the following as of June 30, 2017:

	June 30, 2017	
	Principal Amount	Carrying Amount
	($ in millions)	
7.25% senior notes due 2018	$46	$46
Floating rate senior notes due 2019	380	380
6.625% senior notes due 2020	572	572
6.875% senior notes due 2020	279	279
6.125% senior notes due 2021	550	550
5.375% senior notes due 2021	270	270
4.875% senior notes due 2022	451	451
8.00% senior secured second lien notes due 2022[a]	1,737	2,385
5.75% senior notes due 2023	338	338
8.00% senior notes due 2025	1,000	1,000
5.5% convertible senior notes due 2026[b][c]	1,250	824
8.00% senior notes due 2027	750	750
2.75% contingent convertible senior notes due 2035[d]	2	2
2.5% contingent convertible senior notes due 2037[d]	1	1
2.25% contingent convertible senior notes due 2038[c][d]	9	8
Debt issuance costs	—	44
Discount on senior notes	—	(15)
Interest rate derivatives[e]	—	2
Total senior notes, net	7,635	7,887
Less current maturities of senior notes, net[f]	(3)	(3)
Total long-term senior notes, net	$7,632	$7,884

(a) The carrying amount as of June 30, 2017, includes a premium of $648 million associated with a troubled debt restructuring. The premium is being amortized based on an effective yield method.

(b) The notes are convertible, at the holder’s option, prior to maturity under certain circumstances into cash, common stock or a combination of cash and common stock, at our election. The holders of our convertible senior notes may require us to repurchase the principal amount of the notes upon certain fundamental changes.

(c) The carrying amount as of June 30, 2017, is reflected net of a discount associated with the equity component of our convertible and contingent convertible senior notes of $427 million.

(d) 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. 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 and upon certain fundamental changes. In July 2017, we redeemed our remaining 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037.

(e) 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.

(f) As of June 30, 2017, current maturities of senior notes, net includes our 2.75% Contingent Convertible Notes due 2035 and our 2.5% Contingent Convertible Notes due 2037. As discussed above, we redeemed both series of these notes in July 2017.

For further discussion and details regarding our senior notes and 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 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, 2017, our oil, natural gas and NGL derivative instruments were spread among 10 counterparties. 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 ($732 million as of June 30, 2017) and exploration and production companies that own interests in properties we operate ($208 million as of June 30, 2017). 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 that are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized $6 million, $3 million, $6 million and $4 million, respectively, of bad debt expense related to potentially uncollectible receivables.

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to contractual obligations and off-balance sheet commitments. As of June 30, 2017, these arrangements and transactions included (i) operating lease agreements, (ii) a volumetric production payment (VPP) (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.

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Results of Operations – Three Months Ended June 30, 2017 vs June 30, 2016

General. For the Current Quarter, Chesapeake had net income of $495 million, or $0.47 per diluted common share, on total revenues of $2.281 billion. This compares to a net loss of $1.776 billion, or $2.51 per diluted common share, on total revenues of $1.622 billion for the Prior Quarter. The increase in net income in the Current Quarter is attributable to an increase in the average realized prices we received for oil, natural gas and NGL production. The net loss in the Prior Quarter was primarily driven by non-cash impairments of oil and natural gas properties. See Impairment of Oil and Natural Gas Properties below.

Oil, Natural Gas and NGL Sales. During the Current Quarter, oil, natural gas and NGL sales were $1.279 billion compared to $440 million in the Prior Quarter. In the Current Quarter, Chesapeake sold 48 mmboe for $1.079 billion at a weighted average price of $22.46 per boe (excluding the effect of derivatives), compared to 60 mmboe sold in the Prior Quarter for $884 million at a weighted average price of $14.76 per boe (excluding the effect of derivatives). The increase in the price received per boe in the Current Quarter compared to the Prior Quarter resulted in a $369 million increase in revenues, and decreased sales volumes resulted in a $174 million decrease in revenues, for a total increase in revenues of $195 million (excluding the effect of derivatives).

For the Current Quarter, our average price received per barrel of oil (excluding the effect of derivatives) was $47.51, compared to $43.00 in the Prior Quarter. Natural gas prices received per mcf (excluding the effect of derivatives) were $2.88 and $1.63 in the Current Quarter and the Prior Quarter, respectively. NGL prices received per barrel (excluding the price of derivatives) were $18.36 in the Current Quarter and $13.37 in the Prior Quarter.

Gains (losses) from our oil, natural gas and NGL derivatives resulted in a net increase in oil, natural gas and NGL revenues of $200 million in the Current Quarter and a net decrease of $444 million in the Prior Quarter, respectively. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a listing of all of our derivative instruments as of June 30, 2017.

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 $8 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 $21 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 approximately $5 million.

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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, 2017								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Marcellus	—	—	74	2.54	—	—	13	26	15.25
Haynesville	—	—	66	2.97	—	—	11	23	17.89
Eagle Ford	5	48.28	14	3.44	2	19.40	9	19	36.27
Utica	1	42.47	34	3.20	2	16.96	9	18	20.59
Mid-Continent	1	47.16	18	2.90	1	19.22	5	11	25.68
Powder River Basin	1	47.90	3	2.99	—	—	1	3	31.30
Other[b]	—	—	—	—	—	—	—	—	—
Total	8	47.51	209	2.88	5	18.36	48	100%	22.46

	Three Months Ended June 30, 2016								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Marcellus	—	—	73	1.22	—	—	12	20	7.30
Haynesville	—	—	69	1.85	—	—	12	20	11.13
Eagle Ford	5	44.84	12	2.04	2	13.79	9	14	31.22
Utica	1	37.20	47	1.86	4	11.52	13	21	14.06
Mid-Continent	1	42.57	25	1.53	1	16.55	7	12	17.62
Powder River Basin	1	43.31	4	1.95	—	—	1	2	25.48
Other[b]	—	—	39	1.64	—	—	6	11	10.06
Total	8	43.00	269	1.63	7	13.37	60	100%	14.76

(a) Average sales prices exclude gains and/or losses on derivatives.
(b) Includes Central Texas and Devonian Shale.

Our average daily production of 528 mboe for the Current Quarter consisted of approximately 88 mbbls of oil (17% on an oil equivalent basis), approximately 2.3 bcf of natural gas (72% on an oil equivalent basis) and approximately 57 mbbls of NGL (11% on an oil equivalent basis). Oil production decreased by 2%, natural gas production decreased by 23% and NGL production decreased by 22% year over year primarily as a result of the sale of certain of our Barnett and Mid-Continent assets in 2016 and the sale of certain of our Haynesville Shale assets in 2017.

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,	
	2017	2016
Oil	35	40
Natural gas	56	50
NGL	9	10
Total	100%	100%

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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 of the notes to our condensed consolidated financial statements included 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. We recognized $1.002 billion in marketing, gathering and compression revenues in the Current Quarter with corresponding expenses of $1.027 billion, for a net loss of $25 million. This compares to revenues of $1.182 billion, of which $37 million related to unrealized losses on the fair value of our supply contract derivative, with corresponding expenses of $1.207 billion, for a net loss of $25 million in the Prior Quarter. Although higher oil, natural gas and NGL prices were paid and received in our marketing operations, revenues and expenses decreased in the Current Quarter compared to the Prior Quarter primarily as a result of contract assignments and terminations.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $140 million in the Current Quarter, compared to $182 million in the Prior Quarter. On a unit-of-production basis, production expenses were $2.92 per boe in the Current Quarter compared to $3.05 per boe in the Prior Quarter. The absolute and per unit decrease in the Current Quarter was the result of operating efficiencies across most of our operating areas, as well as the sale of certain oil and natural gas properties in 2016. Production expenses in the Current Quarter and the Prior Quarter included approximately $5 million and $15 million, or $0.10 and $0.25 per boe, respectively, associated with VPP production volumes. In connection with certain 2016 divestitures, we purchased the remaining oil and natural gas interests previously sold in connection with five of our VPPs, and a majority of these repurchased oil and natural gas interests were subsequently sold. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our remaining VPP agreement decrease and operating efficiencies generally improve.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $357 million in the Current Quarter compared to $481 million in the Prior Quarter. On a unit-of-production basis, gathering, processing and transportation expenses were $7.44 per boe in the Current Quarter compared to $8.04 per boe in the Prior Quarter. The absolute and per unit decrease primarily related to divestitures in 2016. A summary of oil, natural gas and NGL gathering, processing and transportation expenses by product is shown below.

	Three Months Ended June 30,	
	2017	2016
Oil ($ per bbl)	$3.70	$3.64
Natural gas ($ per mcf)	$1.37	$1.48
NGL ($ per bbl)	$7.87	$7.61

Production Taxes. Production taxes were $21 million in the Current Quarter compared to $19 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.42 per boe in the Current Quarter compared to $0.32 per boe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil, natural gas and NGL prices are higher. The absolute and per unit increase in production taxes in the Current Quarter was primarily due to higher prices received for our oil, natural gas and NGL production. Production taxes in both the Current Quarter and the Prior Quarter included approximately $1 million, or $0.02 per boe, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses were $70 million in the Current Quarter and $61 million in the Prior Quarter, or $1.45 and $1.02 per boe, respectively. The absolute and per unit expense increase in the Current Quarter was primarily due to less overhead reflected as oil, natural gas and NGL production expenses, as well as less overhead billed to third party working interest owners, resulting from certain divestitures in 2016 and 2017.

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 $31 million and $35 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded expense of $3 million in the Prior Quarter for restructuring and other termination costs primarily related to the reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary and approximately $1 million related to PSU fair value adjustments.

Provision for Legal Contingencies. In the Current Quarter and the Prior Quarter, we recorded expense of $17 million and $71 million, respectively, for legal contingencies. Both the Current Quarter and the Prior Quarter provisions consist of adjustments for loss contingencies primarily related to royalty claims. 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 royalty claims.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $202 million and $277 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 $4.21 and $4.64 in the Current Quarter and the Prior Quarter, respectively. The decrease in the Current Quarter was primarily the result of decreased production as a result of the sale of certain of our Barnett and Mid-Continent assets in 2016 and the sale of certain of our Haynesville Shale assets in 2017.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $21 million in the Current Quarter compared to $29 million in the Prior Quarter. On a unit-of-production basis, depreciation and amortization of other assets was $0.43 per boe in the Current Quarter compared to $0.48 per boe in the Prior Quarter. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. 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 Useful Life
	2017	2016	
	($ in millions)		(in years)
Buildings and improvements	$ 9	$ 10	10 – 39
Computers and office equipment	5	5	5 – 7
Natural gas compressors[(a)]	4	7	3 – 20
Vehicles	1	1	5
Natural gas gathering systems and treating plants[(a)]	—	3	20
Other	2	3	5 – 12
Total depreciation and amortization of other assets	$ 21	$ 29	

(a) Included in our marketing, gathering and compression 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 a ceiling 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. In the Current Quarter, capitalized costs of oil and natural gas properties did not exceed the ceiling. For the Prior Quarter, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment of the carrying value of our oil and natural gas properties of $1.070 billion.

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Impairments of Fixed Assets and Other. In the Current Quarter and the Prior Quarter, we recognized $26 million and $6 million, respectively, of fixed asset impairment losses and other charges. In the Current Quarter, we terminated future natural gas transportation commitments related to divested assets for a cash payment of $23 million. The Prior Quarter amount primarily related to charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices.

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 $1 million in the Prior Quarter. The Current Quarter amounts primarily related to the sale of compressors. The Prior Quarter amounts primarily related to the sale of buildings, land and other property and equipment.

Interest Expense. Interest expense was $93 million in the Current Quarter compared to $62 million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2017	2016
	($ in millions)	
Interest expense on senior notes	$136	$148
Interest expense on term loan	32	—
Amortization of loan discount, issuance costs and other	6	7
Amortization of premium associated with troubled debt restructuring	(42)	(41)
Interest expense on revolving credit facilities	8	12
Realized gains on interest rate derivatives[(a)]	(1)	(3)
Unrealized (gains) losses on interest rate derivatives[(b)]	1	2
Capitalized interest	(47)	(63)
Total interest expense	$93	$62
Average senior notes borrowings	$7,600	$8,926
Average credit facilities borrowings	$351	$457
Average term loan borrowings	$1,500	$—

(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 interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

The decrease in interest expense on senior notes is due to the decrease in the average outstanding principal amount of senior notes. The decrease in capitalized interest resulted from lower average balances of unproved oil and natural gas properties, the primary asset on which interest is capitalized. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.92 per boe in the Current Quarter compared to $1.00 per boe in the Prior Quarter.

Losses on Investments. Losses on investments of $2 million in the Prior Quarter were related to our equity investment in Sundrop Fuels, Inc.

Gains (Losses) on Purchases or Exchanges of Debt. In the Current Quarter, we retired $682 million principal amount of our outstanding senior secured second lien notes through a tender offer for $750 million. We recorded an aggregate gain of approximately $191 million associated with the transaction.

In the Prior Quarter, we privately negotiated exchanges of approximately $472 million principal amount of our outstanding senior notes and contingent convertible senior notes for 92,096,360 common shares. We recorded an aggregate gain of approximately $68 million associated with these debt exchanges.

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Other Income (Expense). Chesapeake recorded $1 million other expense in the Current Quarter and $3 million of other income in the Prior Quarter. The Current Quarter other expense consisted primarily of miscellaneous expenses. The Prior Quarter other income consisted of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax expense of $1 million in the Current Quarter. Our effective income tax rate was 0.2% in the Current Quarter and 0.0% in the Prior Quarter. The increase in the effective income tax rate from the Prior Quarter to the Current Quarter is primarily due to the accrual of current state income tax expenses in the Current Quarter. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of income tax expense (benefit).

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $1 million and a nominal amount in the Current Quarter and the Prior Quarter, respectively. In both quarters, activity was attributable to the Chesapeake Granite Wash Trust.

Results of Operations – Six Months Ended June 30, 2017 vs June 30, 2016

General. For the Current Period, Chesapeake had net income of $636 million, or $0.59 per diluted common share, on total revenues of $5.034 billion. This compares to a net loss of $2.844 billion, or $4.21 per diluted common share, on total revenues of $3.575 billion for the Prior Period. The increase in net income in the Current Period is attributable to an increase in the average realized prices we received for oil, natural gas and NGL production, partially offset by charges for terminating certain natural gas and oil transportation commitments. See Impairments of Fixed Assets and Other below. The net loss in the Prior Period was primarily driven by non-cash impairments of oil and natural gas properties. See Impairment of Oil and Natural Gas Properties below.

Oil, Natural Gas and NGL Sales. During the Current Period, oil, natural gas and NGL sales were $2.748 billion compared to $1.433 billion in the Prior Period. In the Current Period, Chesapeake sold 96 mmboe for $2.226 billion at a weighted average price of $23.29 per boe (excluding the effect of derivatives), compared to 121 mmboe sold in the Prior Period for $1.696 billion at a weighted average price of $14.01 per boe (excluding the effect of derivatives). The increase in the price received per boe in the Current Period compared to the Prior Period resulted in an $887 million increase in revenues, and decreased sales volumes resulted in a $357 million decrease in revenues, for a total increase in revenues of $530 million (excluding the effect of derivatives).

For the Current Period, our average price received per barrel of oil (excluding the effect of derivatives) was $48.83, compared to $35.98 in the Prior Period. Natural gas prices received per mcf (excluding the effect of derivatives) were $2.99 and $1.69 in the Current Period and the Prior Period, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $20.99 and $12.43 in the Current Period and the Prior Period, respectively.

Gains from our oil, natural gas and NGL derivatives resulted in a net increase in oil, natural gas and NGL revenues of $522 million in the Current Period and a net decrease of $263 million in the Prior Period, respectively. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a listing of all of our derivative instruments as of June 30, 2017.

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 $16 million and $15 million, respectively, 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 $42 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 approximately $10 million.

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, 2017								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Marcellus	—	—	153	2.76	—	—	25	26	16.59
Haynesville	—	—	131	2.98	—	—	22	22	17.92
Eagle Ford	10	49.58	26	3.42	3	20.37	18	19	37.37
Utica	2	43.88	68	3.35	5	21.20	17	19	22.35
Mid-Continent	3	48.69	36	2.95	2	20.96	11	11	26.41
Powder River Basin	1	48.62	6	3.14	—	—	3	3	31.87
Other[b]	—	—	—	—	—	—	—		—
Total	16	48.83	420	2.99	10	20.99	96	100%	23.29

	Six Months Ended June 30, 2016								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Marcellus	—	—	152	1.33	—	—	25	21	7.96
Haynesville	—	—	130	1.86	—	—	22	18	11.16
Eagle Ford	10	37.44	25	2.08	3	12.33	17	14	26.79
Utica	3	30.51	95	1.92	6	12.01	25	21	13.79
Mid-Continent	3	36.20	58	1.67	3	13.20	16	13	16.11
Powder River Basin	1	36.73	7	2.00	1	15.51	3	2	22.92
Other[b]	—	—	79	1.70	—	—	13	11	10.28
Total	17	35.98	546	1.69	13	12.43	121	100%	14.01

(a) Average sales prices exclude gains and/or losses on derivatives.
(b) Includes Central Texas and Devonian Shale.

Our average daily production of 528 mboe for the Current Period consisted of approximately 86 mbbls of oil (16% on an oil equivalent basis), approximately 2.3 bcf of natural gas (73% on an oil equivalent basis) and approximately 55 mbbls of NGL (11% on an oil equivalent basis). Oil production decreased by 8%, natural gas production decreased by 23% and NGL production decreased by 23% year over year primarily as a result of the sale of certain of our Barnett and Mid-Continent assets in 2016 and the sale of certain of our Haynesville Shale assets in 2017.

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,	
	2017	2016
Oil	34	36
Natural gas	57	54
NGL	9	10
Total	100%	100%

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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 of the notes to our condensed consolidated financial statements included 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. We recognized $2.286 billion in marketing, gathering and compression revenues in the Current Period with corresponding expenses of $2.355 billion, for a net loss of $69 million. This compares to revenues of $2.142 billion, of which $17 million related to unrealized losses on the fair value of our supply contract derivative, with corresponding expenses of $2.149 billion, for a net loss of $7 million in the Prior Period. Revenues and expenses increased in the Current Period compared to the Prior Period primarily as a result of higher oil, natural gas and NGL prices paid and received in our marketing operations. The margin decrease in the Current Period as compared to the Prior Period was primarily the result of the sale of a significant portion of our gathering and compression assets, concurrently with the associated upstream assets. Additionally, the Current Period includes losses on certain transportation contracts with third parties associated with assets divested in the fourth quarter of 2016.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $275 million in the Current Period, compared to $388 million in the Prior Period. On a unit-of-production basis, production expenses were $2.88 per boe in the Current Period compared to $3.21 per boe in the Prior Period. The absolute and per unit decrease in the Current Period was the result of operating efficiencies across most of our operating areas, as well as the sale of certain oil and natural gas properties in 2016. Production expenses in the Current Period and the Prior Period included approximately $11 million and $28 million, or $0.11 and $0.23 per boe, respectively, associated with VPP production volumes. In connection with certain 2016 divestitures, we purchased the remaining oil and natural gas interests previously sold in connection with five of our VPPs, and a majority of these repurchased oil and natural gas interests were subsequently sold. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our remaining VPP agreement decrease and operating efficiencies generally improve.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $712 million in the Current Period compared to $963 million in the Prior Period. On a unit-of-production basis, gathering, processing and transportation expenses were $7.45 per boe in the Current Period compared to $7.96 per boe in the Prior Period. The absolute and per unit decrease primarily related to divestitures in 2016. A summary of oil, natural gas and NGL gathering, processing and transportation expenses by product is shown below.

	Six Months Ended June 30, 2017	2016
Oil ($ per bbl)	$3.77	$3.46
Natural gas ($ per mcf)	$1.36	$1.47
NGL ($ per bbl)	$8.16	$7.60

Production Taxes. Production taxes were $43 million in the Current Period compared to $37 million in the Prior Period. On a unit-of-production basis, production taxes were $0.45 per boe in the Current Period compared to $0.31 per boe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil, natural gas and NGL prices are higher. The absolute and per unit increase in production taxes in the Current Period was primarily due to higher prices received for our oil, natural gas and NGL production. Production taxes in the Prior Period included $2 million, $0.02 per boe associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses were $135 million in the Current Period and $109 million in the Prior Period, or $1.40 and $0.90 per boe, respectively. The absolute and per unit expense increase in the Current Period was primarily due to less overhead reflected as oil, natural gas and NGL production expenses, as well as less overhead billed to third party working interest owners, resulting from certain divestitures in 2016 and 2017.

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 $67 million and $72 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded an expense of $3 million in the Prior Period for restructuring and other termination costs primarily related to the reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary and approximately $1 million related to PSU fair value adjustments.

Provision for Legal Contingencies. In the Current Period and the Prior Period, we recorded expense of $15 million and $104 million, respectively, for legal contingencies. Both the Current Period and the Prior Period provisions consist of adjustments for loss contingencies primarily related to royalty claims. 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 royalty claims.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $399 million and $540 million 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 $4.18 and $4.47 in the Current Period and the Prior Period, respectively. The decrease in the Current Period was primarily the result of decreased production as a result of the sale of certain of our Barnett and Mid-Continent assets in 2016 and the sale of certain of our Haynesville Shale assets in 2017.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $42 million in the Current Period compared to $58 million in the Prior Period. On a unit-of-production basis, depreciation and amortization of other assets was $0.44 per boe in the Current Period compared to $0.48 per boe in the Prior Period. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. 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
	2017	2016	
	($ in millions)		(in years)
Buildings and improvements	$ 18	$ 20	10 – 39
Computers and office equipment	10	9	5 – 7
Natural gas compressors[(a)]	8	15	3 – 20
Vehicles	1	2	5
Natural gas gathering systems and treating plants[(a)]	—	5	20
Other	5	7	5 – 12
Total depreciation and amortization of other assets	$ 42	$ 58	

(a) Included in our marketing, gathering and compression 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 a ceiling 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. In the Current Period, capitalized costs of oil and natural gas properties did not exceed the ceiling. For the Prior Period, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment of the carrying value of our oil and natural gas properties of $2.067 billion.

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Impairments of Fixed Assets and Other. In the Current Period and the Prior Period, we recognized $417 million and $44 million, respectively, of fixed asset impairment losses and other charges. In the Current Period, we paid $290 million to assign an oil transportation agreement to a third party. In addition, we terminated future natural gas transportation commitments related to divested assets for a cash payment of $126 million. The Prior Period amount primarily related to impairments of certain of our buildings, land and compressors as well as charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices.

Net (Gains) Losses on Sales of Fixed Assets. In the Current Period, net losses on sales of fixed assets were $1 million compared to net gains of $5 million in the Prior Period. The Current Period and the Prior Period amounts primarily related to the sale of buildings, land and other property and equipment.

Interest Expense. Interest expense was $188 million in the Current Period compared to $124 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2017	2016
	($ in millions)	
Interest expense on senior notes	$272	$305
Interest expense on term loan	64	—
Amortization of loan discount, issuance costs and other	15	18
Amortization of premium associated with troubled debt restructuring	(83)	(83)
Interest expense on revolving credit facilities	17	17
Realized gains on interest rate derivatives[a]	(2)	(6)
Unrealized losses on interest rate derivatives[b]	3	5
Capitalized interest	(98)	(132)
Total interest expense	$188	$124
Average senior notes borrowings	$7,644	$9,246
Average credit facilities borrowings	$176	$263
Average term loan borrowings	$1,500	$—

(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 interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

The decrease in interest expense on senior notes is due to the decrease in the average outstanding principal amount of senior notes. The decrease in capitalized interest resulted from lower average balances of unproved oil and natural gas properties, the primary asset on which interest is capitalized. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.94 per boe in the Current Period compared to $0.99 per boe in the Prior Period.

Losses on Investments. Losses on investments of $2 million in the Prior Period were related to our equity investment in Sundrop Fuels, Inc.

Loss on Sale of Investment. In the Prior Period, we sold certain of our mineral interests and assigned our partnership interest in Mineral Acquisition Company I, L.P. to KKR Royalty Aggregator LLC. As a result of the transaction, we wrote off our equity investment and recognized a $10 million loss.

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Gains (Losses) on Purchases or Exchanges of Debt. In the Current Period, we retired $1.604 billion principal amount of our outstanding senior notes, senior secured second lien notes and contingent convertible notes through purchases in the open market, tender offers or repayment upon maturity for $1.746 billion, which included the maturity of our 6.25% Euro-denominated Senior Notes due 2017 and the corresponding cross currency swap. We recorded an aggregate gain of approximately $184 million associated with the repurchases and tender offers.

In the Prior Period, we retired $558 million principal amount of our outstanding senior notes and contingent convertible senior notes through purchases in the open market, tender offers or repayment upon maturity for $472 million. Additionally, we privately negotiated an exchange of approximately $577 million principal amount of our outstanding senior notes and contingent convertible senior notes for 109,351,707 common shares. We recorded an aggregate gain of approximately $168 million associated with the repurchases and exchanges.

Other Income. Other income was $2 million and $6 million in the Current Period and the Prior Period, respectively. The Current Period other income consisted primarily of miscellaneous income. The Prior Period other income consisted of $1 million of interest income and $5 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax expense of $2 million in the Current Period. Our effective income tax rate was 0.3% in the Current Period and 0.0% in the Prior Period. The increase in the effective income tax rate from the Prior Period to the Current Period is primarily due to the accrual of current state income tax expenses in the Current Period. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of income tax expense (benefit).

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $2 million and a nominal amount in the Current Period and the Prior Period, respectively. In both periods, activity was attributable to the Chesapeake Granite Wash Trust.

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 (including the use of joint venture drilling carries), 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 fund planned capital expenditures and debt service requirements and comply with financial maintenance covenants, meet contractual cash commitments to third parties, debt repurchases, operating and capital efficiencies, business strategy, the effect of our remediation plan for a material weakness, and other plans and objectives for future operations. Disclosures concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2016 (2016 Form 10-K) and include:

- the volatility of oil, natural gas and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- our inability to access the capital markets on favorable terms;
- the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations;
- our credit rating requiring us to post more collateral under certain commercial arrangements;
- write-downs of our oil and natural gas asset carrying values due to low commodity prices;
- our ability to replace reserves and sustain production;

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- 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;
- charges incurred in response to market conditions and in connection with our ongoing 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;
- impacts of potential legislative and regulatory actions addressing climate change;
- federal and state tax proposals affecting our industry;
- potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations;
- 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;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- potential challenges by SSE’s former creditors of our spin-off of in connection with SSE’s recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code;
- an interruption in operations at our headquarters due to a catastrophic event;
- the continuation of suspended dividend payments on our common stock;
- the effectiveness of our remediation plan for a material weakness;
- certain anti-takeover provisions that affect shareholder rights; and
- our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means.

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 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.

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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 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 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.

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, 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 that 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 consolidated financial statements included in Item 1 of Part I of this report for further discussion of the fair value measurements associated with our derivatives.

As of June 30, 2017, our oil, natural gas and NGL 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.
- 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.
- 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.
- 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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As of June 30, 2017, 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	12	$50.40	$—	$—	$ —	$ 43
Long-term	1	$51.43	$—	$—	$ —	2
Call Options (sold):						
Short-term	3	$—	$83.50	$—	$ —	—
Total Oil						45
	(tbtu)	($ per mmbtu)				
Natural Gas:						
Swaps:						
Short-term	540	$3.16	$—	$—	$ —	21
Long-term	164	$2.95	$—	$—	$ —	7
Collars:						
Short-term	47	$—	$3.46	$3.13	$ —	6
Long-term	24	$—	$3.25	$3.00	$ —	4
Call Options (sold):						
Short-term	35	$—	$10.23	$—	$ —	—
Long-term	55	$—	$12.00	$—	$ —	—
Basis Protection Swaps:						
Short-term	13	$—	$—	$—	$ (0.51)	(2)
Total Natural Gas						36
Total Estimated Fair Value						$ 81

In addition to the open derivative positions disclosed above, as of June 30, 2017, we had $39 million of net derivative losses 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, 2017
	($ in millions)
Short-term	$ 30
Long-term	(69)
Total	$ (39)

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The table below reconciles the changes in fair value of our oil and natural gas derivatives during the Current Period. Of the $81 million fair value asset as of June 30, 2017, a $68 million asset relates to contracts maturing in the next 12 months and a $13 million asset relates to contracts maturing after 12 months. All open derivative instruments as of June 30, 2017 are expected to mature by December 31, 2020.

	June 30, 2017
	($ in millions)
Fair value of contracts outstanding, as of January 1, 2017	$ (504)
Change in fair value of contracts	540
Contracts realized or otherwise settled	45
Fair value of contracts outstanding, as of June 30, 2017	$ 81

The change in oil and natural gas prices during the Current Period decreased the liability related to our derivative instruments by $540 million. This unrealized gain is recorded in oil, natural gas and NGL sales. We settled contracts in the Current Period that were in a liability position for $45 million. Realized gains and losses 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, 2017, we had total debt of $9.710 billion, including $7.255 billion of fixed rate debt at interest rates averaging 6.87% and $2.455 billion of floating rate debt at an interest rate of 6.72%.

	Years of Maturity						
	2017	2018	2019	2020	2021	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$1	$55	$—	$853	$820	$5,526	$7,255
Average interest rate	2.50%	6.45%	— %	6.70 %	5.88 %	7.04 %	6.87 %
Debt – variable rate	$—	$—	$955	$—	$1,500	$—	$2,455
Average interest rate	— %	— %	3.92 %	— %	8.50 %	— %	6.72 %

(a) This amount excludes the premium, discount and deferred financing costs included in debt of $141 million and interest rate derivatives of $2 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, term loan 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, 2017, there were no interest rate derivatives outstanding.

As of June 30, 2017, we had $10 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 six-year term of our related senior notes.

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

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Foreign Currency Derivatives

During the Current Period, both our 6.25% Euro-denominated Senior Notes due 2017 and cross currency swaps for the same principal amount matured. Upon maturity of the notes, the counterparties paid us €246 million and we paid the counterparties $327 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. The swaps were designated as cash flow hedges and, because they were 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 did not impact earnings. The fair values of the cross currency swaps were recorded on the condensed consolidated balance sheet as a liability of $73 million as of December 31, 2016.

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 on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were not effective as of June 30, 2017, because of the material weakness in our internal control over financial reporting described in Management’s Report on Internal Control Over Financial Reporting appearing under Item 8 of Part II of our Annual Report on Form 10-K for the year ended December 31, 2016.

Remediation Plan for the Material Weakness

Our management is actively engaged in remediation efforts to address the material weakness identified. Specifically, our management is in the process of implementing a control related to reviewing the configuration of the basis price differential calculations, including a control activity to verify any subsequent changes are appropriately reviewed and that the interface control is designed to validate the data at an appropriately disaggregated level. Our management believes that these actions will remediate the material weakness in internal control over financial reporting.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2017, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION
ITEM 1. Legal Proceedings
Litigation and Regulatory Proceedings
The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is currently indeterminate. See Note 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.
Regulatory and Related 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 natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.
In addition, the Company received a DOJ subpoena and a voluntary document request from the SEC seeking information on our accounting methodology for the acquisition and classification of oil and natural gas properties and related matters. On October 4, 2016, a securities class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and certain current directors and officers of the Company alleging, among other things, violations of federal securities laws for purported misstatements in the Company's SEC filings and other public disclosures regarding the Company's accounting for the acquisition and classification of oil and natural gas properties. On June 20, 2017, the DOJ orally advised Chesapeake that it was closing its investigation, and on July 17, 2017, the SEC indicated by letter that it had concluded its investigation and that it did not intend to recommend an enforcement action on the matter. The related securities class action was dismissed on March 14, 2017.
On July 10, 2017, Chesapeake, its Benefits Committee, its Investment Committee and certain employees were named as defendants in a purported Employee Retirement Income Security Act of 1974 (ERISA) class action filed in the United States District Court for the Western District of Oklahoma (the "ERISA Lawsuit"). The ERISA Lawsuit alleges violations of Sections 404, 405, 409 and 502 of ERISA with respect to the Company's common stock held in its Savings and Incentive Stock Bonus Plan (the "Plan"). The plaintiffs seek to represent a class of persons who were participants in the Plan after June 1, 2014. The plaintiffs also seek damages, imposition of a constructive trust and other relief, including attorneys' fees, based on allegations that the defendants breached their fiduciary duties by continuing to allow the Company's common stock to remain as an investment option under the Plan during the class period.
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.
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. Plaintiffs have varying royalty provisions in their respective leases. Oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. 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, Texas, Pennsylvania, Ohio, Oklahoma, Kentucky, 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.

Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. These lawsuits, organized for pre-trial proceedings with respect to the Barnett Shale and Eagle Ford Shale, respectively, generally allege that Chesapeake underpaid royalties by making improper deductions, using incorrect production volumes and similar theories. Chesapeake expects that additional lawsuits will continue to be pursued and that new plaintiffs will file other lawsuits making similar allegations.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit includes other UTPCPL claims and antitrust claims, including that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and a permanent injunction from further violations of the UTPCPL.

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 for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources.

The Company is also defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits have been filed in the U.S. District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the U.S. District Court of Kansas, in each case against the Company and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney’s fees, costs and interest, as well as enjoinment from adopting practices or plans that would restrain competition in a similar manner as alleged in the lawsuits.

Environmental Proceedings

Our subsidiary Chesapeake Appalachia, LLC (CALLC) is engaged in discussions with the EPA, 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.

On December 27, 2016, we received a Finding of Violation from the EPA alleging violations of the Clean Air Act at a number of locations in Ohio. We have exchanged information with the EPA and are engaged in discussions aimed at resolving the allegations. Resolution of the matter may result in monetary sanctions of more than $100,000.

We are named as a defendant in a number of putative class actions in Oklahoma alleging that we and several other companies have engaged in activities that have caused earthquakes. These actions seek, among other things, compensation for injury to real property, reimbursement of insurance premiums, and punitive damages.

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 2016 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.

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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, 2017:

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, 2017 through April 30, 2017	6,089	$ 5.86	—	$ —
May 1, 2017 through May 31, 2017	1,385	$ 5.06	—	$ —
June 1, 2017 through June 30, 2017	128,009	$ 5.10	—	$ —
Total	135,483	$ 5.13	—	

(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, Chesapeake's Board of Directors authorized the repurchase of up to $1 billion of our common stock from time to time. The repurchase program does not have an expiration date. As of June 30, 2017, there have been no repurchases under the program.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

On August 2, the Board of Directors appointed Domenic J. Dell'Osso, who has served as the Company's Executive Vice President and Chief Financial Officer since November 2010, to serve as interim principal accounting officer.

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ITEM 6. Exhibits

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

INDEX OF EXHIBITS

		Incorporated by Reference				Filed or
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Furnished Herewith
3.1.1	Chesapeake's Restated Certificate of Incorporation.					X
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008	
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008	
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010	
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010	
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/19/2014	
4.1	Indenture dated as of April 24, 2014, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Deutsche Bank Trust Company Americas, as trustee.	8-K	001-13726	4.1	4/29/2014	
4.2	Seventh Supplemental Indenture dated as of June 6, 2017 to Indenture dated as of April 24, 2014 with respect to 8.00% Senior Notes due 2027 (includes Form of 8.00% Senior Notes as Exhibit A).	8-K	001-13726	4.2	6/7/2017	
4.3	Registration Rights Agreement dated as of June 6, 2017, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Citigroup Global Markets Inc.	8-K	001-13726	4.4	6/7/2017	
4.4	Fourth Amendment to Credit Agreement dated May 19, 2017 among Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	8-K	001-13726	10.1	5/22/2017	
10.1	Amended and Restated 2014 Long Term Incentive Plan.					X
12						X

Ratios of Earnings to Fixed Charges and Combined
Fixed Charges and Preferred Dividends.

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
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	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 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
101.PRE						