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 March 31, 2018
[ ] 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 [ ]
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 April 23, 2018, there were 911,815,100 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

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

	March 31, 2018	December 31, 2017
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $2 attributable to our VIE)	$ 4	$ 5
Accounts receivable, net	1,082	1,322
Short-term derivative assets	3	27
Other current assets	135	171
Total Current Assets	1,224	1,525
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)	69,284	68,858
Unproved properties	3,326	3,484
Other property and equipment	1,869	1,986
Total Property and Equipment, at Cost	74,479	74,328
Less: accumulated depreciation, depletion and amortization (($462) and ($461) attributable to our VIE)	(63,903)	(63,664)
Property and equipment held for sale, net	16	16
Total Property and Equipment, Net	10,592	10,680
LONG-TERM ASSETS:		
Other long-term assets	270	220
TOTAL ASSETS	$ 12,086	$ 12,425

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

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

	March 31, 2018	December 31, 2017
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 657	$ 654
Current maturities of long-term debt, net	52	52
Accrued interest	139	137
Short-term derivative liabilities	149	58
Other current liabilities ($3 and $3 attributable to our VIE)	1,357	1,455
Total Current Liabilities	2,354	2,356
LONG-TERM LIABILITIES:		
Long-term debt, net	9,325	9,921
Long-term derivative liabilities	6	4
Asset retirement obligations, net of current portion	153	162
Other long-term liabilities	345	354
Total Long-Term Liabilities	9,829	10,441
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 5,603,458 shares outstanding	1,671	1,671
Common stock, $0.01 par value, 2,000,000,000 shares authorized: 911,794,424 and 908,732,809 shares issued	9	9
Additional paid-in capital	14,419	14,437
Accumulated deficit	(16,240)	(16,525)
Accumulated other comprehensive loss	(47)	(57)
Less: treasury stock, at cost; 3,416,465 and 2,240,394 common shares	(32)	(31)
Total Chesapeake Stockholders' Equity (Deficit)	(220)	(496)
Noncontrolling interests	123	124
Total Equity (Deficit)	(97)	(372)
TOTAL LIABILITIES AND EQUITY	$ 12,086	$ 12,425

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

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

	Three Months Ended March 31,	
	2018	2017
	($ in millions except per share data)	
REVENUES:		
Oil, natural gas and NGL	$ 1,243	$ 1,469
Marketing	1,246	1,284
Total Revenues	2,489	2,753
OPERATING EXPENSES:		
Oil, natural gas and NGL production	147	135
Oil, natural gas and NGL gathering, processing and transportation	356	355
Production taxes	31	22
Marketing	1,268	1,328
General and administrative	72	65
Restructuring and other termination costs	38	—
Provision for legal contingencies, net	5	(2)
Oil, natural gas and NGL depreciation, depletion and amortization	268	197
Depreciation and amortization of other assets	18	21
Other operating expense	—	391
Net losses on sales of fixed assets	8	—
Total Operating Expenses	2,211	2,512
INCOME FROM OPERATIONS	278	241
OTHER INCOME (EXPENSE):		
Interest expense	(123)	(95)
Gains on investments	139	—
Losses on purchases or exchanges of debt	—	(7)
Other income	—	3
Total Other Income (Expense)	16	(99)
INCOME BEFORE INCOME TAXES	294	142
Income tax expense	—	1
NET INCOME	294	141
Net income attributable to noncontrolling interests	(1)	(1)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	293	140
Preferred stock dividends	(23)	(23)
Loss on exchange of preferred stock	—	(41)
Earnings allocated to participating securities	(2)	(1)
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	$ 268	$ 75
EARNINGS PER COMMON SHARE:		
Basic	$ 0.30	$ 0.08
Diluted	$ 0.29	$ 0.08
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		
Basic	907	906
Diluted	1,053	907

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

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

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
NET INCOME	$ 294	$ 141
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAX:		
Unrealized gains on derivative instruments, net of income tax expense of $0 and $0	—	4
Reclassification of losses on settled derivative instruments, net of income tax expense of $0 and $0	10	10
Other Comprehensive Income	10	14
COMPREHENSIVE INCOME	304	155
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(1)	(1)
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 303	$ 154

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

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

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 294	$ 141
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	286	218
Derivative (gains) losses, net	117	(322)
Cash receipts (payments) on derivative settlements, net	13	(34)
Stock-based compensation	9	11
Net losses on sales of fixed assets	8	—
Gains on investments	(139)	—
Losses on purchases or exchanges of debt	—	6
Other	(36)	(34)
Changes in assets and liabilities	104	113
Net Cash Provided By Operating Activities	656	99
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(442)	(433)
Acquisitions of proved and unproved properties	(63)	(95)
Proceeds from divestitures of proved and unproved properties	319	892
Additions to other property and equipment	(3)	(3)
Proceeds from sales of other property and equipment	68	19
Proceeds from sales of investments	74	—
Net Cash Provided By (Used In) Investing Activities	(47)	380
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility borrowings	2,904	50
Payments on revolving credit facility borrowings	(3,485)	(50)
Cash paid to purchase debt	—	(982)
Cash paid for preferred stock dividends	(23)	(114)
Distributions to noncontrolling interest owners	(2)	(2)
Other	(4)	(14)
Net Cash Used In Financing Activities	(610)	(1,112)
Net decrease in cash and cash equivalents	(1)	(633)
Cash and cash equivalents, beginning of period	5	882
Cash and cash equivalents, end of period	$ 4	$ 249

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

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

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

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$ 131	$ 92
Income taxes paid, net of refunds received	$ —	$ 1
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$ 103	$ 68
Change in accrued acquisitions of proved and unproved properties	$ —	$ 8
Change in divested proved and unproved properties	$ (12)	$ (8)

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

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

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 1,671	$ 1,771
Exchange/conversions of 0 and 236,048 shares of preferred stock for common stock	—	(100)
Balance, end of period	1,671	1,671
COMMON STOCK:		
Balance, beginning and end of period	9	9
ADDITIONAL PAID-IN CAPITAL:		
Balance, beginning of period	14,437	14,486
Stock-based compensation	5	10
Exchange of preferred stock for 0 and 9,965,835 shares of common stock	—	100
Equity component of contingent convertible notes repurchased, net of tax	—	(20)
Dividends on preferred stock	(23)	(137)
Balance, end of period	14,419	14,439
RETAINED EARNINGS (ACCUMULATED DEFICIT):		
Balance, beginning of period	(16,525)	(17,603)
Net income attributable to Chesapeake	293	140
Cumulative effect of accounting change	(8)	—
Balance, end of period	(16,240)	(17,463)
ACCUMULATED OTHER COMPREHENSIVE LOSS:		
Balance, beginning of period	(57)	(96)
Hedging activity	10	14
Balance, end of period	(47)	(82)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(31)	(27)
Purchase of 1,451,478 and 1,185,517 shares for company benefit plans	(4)	(7)
Release of 275,407 and 38,013 shares from company benefit plans	3	1
Balance, end of period	(32)	(33)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT)	(220)	(1,459)
NONCONTROLLING INTERESTS:		
Balance, beginning of period	124	257
Net income attributable to noncontrolling interests	1	1
Distributions to noncontrolling interest owners	(2)	(2)
Balance, end of period	123	256
TOTAL EQUITY (DEFICIT)	$ (97)	$ (1,203)

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

1. Basis of Presentation

Basis of Presentation

The accompanying condensed consolidated financial statements of Chesapeake were prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and the rules and regulations of the SEC. Pursuant to such rules and regulations, certain disclosures have been condensed or omitted.

This Form 10-Q relates to the three months ended March 31, 2018 (the "Current Quarter") and the three months ended March 31, 2017 (the "Prior Quarter"). Our annual report on Form 10-K for the year ended December 31, 2017 ("2017 Form 10-K") should be read in conjunction with this Form 10-Q. The accompanying condensed consolidated financial statements reflect all normal recurring adjustments which, in the opinion of management, are necessary for a fair statement of our condensed consolidated financial statements and accompanying notes and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which we have a controlling financial interest. Intercompany accounts and balances have been eliminated.

Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) issued *Revenue from Contracts with Customers* (Topic 606) superseding virtually all existing revenue recognition guidance. We adopted this new standard in the first quarter of 2018 using the modified retrospective approach. We applied the new standard to all contracts that were not completed as of January 1, 2018 and reflected the aggregate effect of all modifications in determining and allocating the transaction price. See Note 10 for further details regarding our adoption of Topic 606.

In February 2018, the FASB issued Accounting Standards Update (ASU) 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The new standard allows for stranded tax effects resulting from the Tax Cuts and Jobs Act (the "Tax Act") previously recognized in accumulated other comprehensive income to be reclassified to retained earnings. For public business entities, the amendments are effective for annual periods, including interim periods within the annual periods, beginning after December 15, 2018. Early adoption is permitted in any interim or annual period, but we do not plan to early adopt. We are currently evaluating the impact of this standard on our consolidated financial statements and related disclosures.

In August 2017, the FASB issued ASU 2017-12*, Derivatives and Hedging (Topic 815),* which makes significant changes to the current hedge accounting guidance. The new standard eliminates the requirement to separately measure and report hedge ineffectiveness and generally requires the entire change in the fair value of a hedging instrument to be presented in the same income statement line as the hedged item. The new standard also eases certain documentation and assessment requirements and modifies the accounting for components excluded from the assessment of hedge effectiveness. The new standard update is effective for annual and interim periods beginning after December 15, 2018, including interim periods within those annual periods. Early adoption is permitted, but we do not plan to early adopt. We are currently evaluating the impact of this standard on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* which updated lease accounting guidance requiring lessees to recognize most leases, including operating leases, on the balance sheet as a right-of-use asset and lease liability for leases with terms in excess of 12 months. In January 2018, the FASB issued an update permitting an entity to elect an optional transition practical expedient to not evaluate land easements that existed or expired before the adoption of Topic 842 and were not previously accounted for as leases. Currently the guidance would be applied using a modified retrospective transition method, which requires applying the new guidance to leases that exist or are entered into after the beginning of the earliest period in the financial statements. However, the FASB recently issued Proposed ASU No. 2018-200, *Leases (Topic 842), Targeted Improvements* which would allow entities to apply the transition provisions of the new standard at its adoption date instead of at the earliest comparative period presented in the consolidated financial statements. The proposed ASU will allow entities to continue to apply the legacy guidance in Topic 840, including its disclosure requirements, in the comparative periods presented in the year the new leases standard is adopted. Entities that elect this option would still adopt the new leases standard using a modified retrospective transition method, but would recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption rather than in the earliest period presented. Early adoption is permitted, but we do not plan to early adopt. The standard will not apply to our leases of mineral rights. We are continuing to evaluate the impact of this standard on our consolidated financial statements and related disclosures.

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 all periods presented, 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.

A reconciliation of basic EPS and diluted EPS for the Current Quarter and the Prior Quarter is as follows:

	Three Months Ended March 31,	
	2018	2017
	(in millions, except per share data)	
Net income available to common stockholders	$ 268	$ 75
Effect of dilutive securities	36	—
Diluted income per share	$ 304	$ 75
Weighted average common and common equivalent shares outstanding - basic	907	906
Effect of dilutive securities	146	1
Weighted average common and common equivalent shares outstanding - diluted	1,053	907
Net income per share attributable to Chesapeake:		
Basic	$ 0.30	$ 0.08
Diluted	$ 0.29	$ 0.08
Shares of common stock for the following dilutive securities were excluded from the calculation of diluted EPS as the effect was antidilutive:		
Common stock equivalent of our preferred stock outstanding	60	60
Common stock equivalent of our convertible senior notes outstanding	—	146
Common stock equivalent of our preferred stock outstanding prior to exchange	—	1
Participating securities	—	1

3. Debt

Our long-term debt consisted of the following as of March 31, 2018 and December 31, 2017:

	March 31, 2018		December 31, 2017	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
7.25% senior notes due 2018	$ 44	$ 44	$ 44	$ 44
Floating rate senior notes due 2019	380	380	380	380
6.625% senior notes due 2020	437	437	437	437
6.875% senior notes due 2020	227	227	227	227
6.125% senior notes due 2021	548	548	548	548
5.375% senior notes due 2021	267	267	267	267
4.875% senior notes due 2022	451	451	451	451
8.00% senior secured second lien notes due 2022	1,416	1,870	1,416	1,895
5.75% senior notes due 2023	338	338	338	338
8.00% senior notes due 2025	1,300	1,290	1,300	1,290
5.5% convertible senior notes due 2026[a][b]	1,250	844	1,250	837
8.00% senior notes due 2027	1,300	1,298	1,300	1,298
2.25% contingent convertible senior notes due 2038[a]	9	8	9	8
Term loan due 2021	1,233	1,233	1,233	1,233
Revolving credit facility	200	200	781	781
Debt issuance costs	—	(60)	—	(63)
Interest rate derivatives	—	2	—	2
Total debt, net	9,400	9,377	9,981	9,973
Less current maturities of long-term debt, net[c]	(53)	(52)	(53)	(52)
Total long-term debt, net	$ 9,347	$ 9,325	$ 9,928	$ 9,921

(a) 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 2.25% Contingent Convertible Senior Notes due 2038 and our 5.5% Convertible Senior Notes due 2026 are 8.0% and 11.5%, respectively.

(b) Prior to maturity under certain circumstances and at the holder's option, the notes are convertible. During the first quarter of 2018, the price of our common stock was below the threshold level for conversion and, as a result, the holders do not have the option to convert their notes in the second quarter of 2018.

(c) As of March 31, 2018, current maturities of long-term debt, net includes our 7.25% Senior Notes due December 2018 and our 2.25% Contingent Convertible Notes due December 2038.

Debt Retirements

In the Prior Quarter, we retired $908 million principal amount of our outstanding senior notes and contingent convertible notes through purchases in the open market, tender offers or repayment upon maturity for $982 million. For the open market repurchases and tender offers, we recorded an aggregate net loss of approximately $7 million.

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 March 31, 2018, we had outstanding borrowings of $200 million under the revolving credit facility and had used $157 million of the revolving credit facility for various letters of credit. Borrowings under the revolving credit facility bear interest at a variable rate. 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. Our next borrowing base redetermination is scheduled for the second quarter of 2018.

Our revolving credit facility is subject to various financial and other covenants. As of March 31, 2018, we were in compliance with all applicable financial covenants under the credit agreement and we were able to borrow up to the full availability under the revolving credit facility.

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:

	March 31, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$ 52	$ 53	$ 52	$ 53
Long-term debt (Level 1)	$ 2,635	$ 2,603	$ 2,633	$ 2,629
Long-term debt (Level 2)	$ 6,690	$ 6,582	$ 7,286	$ 7,301

4. Contingencies and Commitments

There have been no material developments in previously reported legal or environmental contingencies or commitments other than the items discussed below. For a discussion of commitments and contingencies, see “Contingencies and Commitments,” Note 4 to the Consolidated Financial Statements in our 2017 Form 10-K.

Contingencies

Regulatory and Related Proceedings. We have previously disclosed receiving U.S. Postal Service and state subpoenas seeking information on our royalty payment practices. The U.S. Postal Service inquiry and all outstanding state subpoenas have been resolved.

We have also previously disclosed 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 us 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. On April 12, 2018, we reached a tentative settlement to resolve substantially all Oklahoma civil class action antitrust cases for an immaterial amount.

We recently received a demand letter from the Healthcare of Ontario Pension Plan (HOOPP) regarding HOOPP’s purchase of our interest in Chaparral Energy, Inc. stock for $215 million on January 5, 2014. HOOPP claims that the Company engaged in material misrepresentations and fraud, and that we violated the Exchange Act and Oklahoma Uniform Securities Act. HOOPP seeks $215 million in monetary damages, plus interest, attorney’s fees, disgorgement and punitive damages. We expect a lawsuit will be filed, and we intend to vigorously defend it.

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 consolidated balance sheets; however, they are reflected in our estimates of proved reserves.

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:

	March 31, 2018
	($ in millions)
2018	$ 815
2019	1,052
2020	980
2021	884
2022	772
2023 – 2035	4,406
Total	$ 8,909

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 may vary with the applicable agreement.

5. Other Liabilities

Other current liabilities as of March 31, 2018 and December 31, 2017 are detailed below:

	March 31, 2018	December 31, 2017
	($ in millions)	
Revenues and royalties due others	$ 584	$ 612
Accrued drilling and production costs	297	216
Joint interest prepayments received	76	74
Accrued compensation and benefits	125	214
Accrued restructuring and other termination costs	27	—
Other accrued taxes	41	43
Other	207	296
Total other current liabilities	$ 1,357	$ 1,455

Other long-term liabilities as of March 31, 2018 and December 31, 2017 are detailed below:

	March 31, 2018	December 31, 2017
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$ 153	$ 156
Unrecognized tax benefits	98	101
Other	94	97
Total other long-term liabilities	$ 345	$ 354

(a) The CHK Utica, L.L.C. investors' right to receive proportionately an overriding royalty interest (ORRI) in the first 1,500 net wells drilled on certain of our Utica Shale leasehold runs through 2023. We have the right to repurchase the ORRIs in the remaining net wells once we have drilled a minimum of 1,300 net wells. As of March 31, 2018, we had drilled 584 net wells. The obligation to deliver future ORRIs, which has been recorded as a liability, will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis. As of March 31, 2018 and December 31, 2017, approximately $30 million of the total ORRI obligations are recorded in other current liabilities.

6. Income Taxes

We estimate our annual effective tax rate for continuing operations in recording our quarterly income tax provision (or benefit) for the various jurisdictions in which we operate. The tax effects of statutory rate changes, significant unusual or infrequent items, and certain changes in the assessment of the realizability of deferred tax assets are excluded from the determination of our annual effective tax rate as such items are recognized as discrete items in the quarter in which they occur.

For the Current Quarter, our effective tax rate remains nominal as a result of maintaining a valuation allowance against substantially all of our net deferred tax asset. Based on our projected operating results for the subsequent 2018 quarters, we project remaining in a net deferred tax asset position as of December 31, 2018. Based on all available positive and negative evidence, including estimates of future taxable income, we believe it is more-likely-than-not that these deferred tax assets will not be realized. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the rolling three-year period ending March 31, 2018, which limits our ability to consider other subjective positive evidence, such as our projections for future growth and earnings. A valuation allowance was recorded against substantially all of our net deferred tax asset as of both December 31, 2017 and March 31, 2018.

We are subject to U.S. federal income tax as well as income and capital taxes in various state jurisdictions. During the Current Quarter, the federal tax examination by the Internal Revenue Service (IRS) of taxable years 2010 through 2013 was settled. Based on new information available in the Current Quarter and the expectation that certain statute of limitations should expire during 2018, we anticipate a $14 million estimated reduction to the liability for state unrecognized tax benefits resulting in an $11 million estimated income tax benefit being recorded as early as the next quarter.

On December 22, 2017, the President of the United States signed into law the Tax Act, which substantially revised numerous areas of U.S. federal income tax law, including reducing the tax rate for corporations from a maximum rate of 35% to a flat rate of 21% and eliminating the corporate alternative minimum tax (AMT). The various estimates included in determining our tax provision as of December 31, 2017 remain provisional through the three months ended March 31, 2018 and may be adjusted through subsequent events such as the filing of the 2017 consolidated federal income tax return and the issuance of additional guidance such as new Treasury Regulations. Moreover, we are still in the process of evaluating the full impact of the Tax Act both at the federal and state level.

7. Share-Based Compensation

Our share-based compensation program consists of restricted stock, stock options, performance share units (PSUs) and cash restricted stock units (CRSUs) granted to employees and restricted stock granted to non-employee directors under our long term incentive plans. The restricted stock and stock options are equity-classified awards and the PSUs and CRSUs 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 Quarter is presented below:

	Shares of Unvested Restricted Stock	Weighted Average Grant Date Fair Value
	(in thousands)	
Unvested restricted stock as of January 1, 2018	13,178	$ 6.37
Granted	2,805	$ 3.02
Vested	(4,651)	$ 7.64
Forfeited	(465)	$ 6.24
Unvested restricted stock as of March 31, 2018	10,867	$ 4.97

The aggregate intrinsic value of restricted stock that vested during the Current Quarter was approximately $15 million based on the stock price at the time of vesting.

As of March 31, 2018, there was approximately $40 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 2.02 years.

Stock Options. In the Current Quarter and the Prior Quarter, 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 our common stock on the grant date. Outstanding options expire seven years 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 our dividend policy, over the expected life of the option. We used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in the Current Quarter:

Expected option life – years	6.0
Volatility	63.55%
Risk-free interest rate	2.72%
Dividend yield	—%

The following table provides information related to stock option activity in the Current Quarter:

	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, 2018	16,285	$ 8.25	7.73	$ 1
Granted	3,611	$ 3.01		
Exercised	—	$ —		$ —
Expired	(64)	$ 20.77		
Forfeited	(267)	$ 5.45		
Outstanding as of March 31, 2018	19,565	$ 7.28	7.93	$ —
Exercisable as of March 31, 2018	8,776	$ 10.88	6.52	$ —

(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 March 31, 2018, there was $23 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.14 years.

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

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
General and administrative expenses	$ 7	$ 8
Oil and natural gas properties	2	4
Oil, natural gas and NGL production expenses	2	3
Total restricted stock and stock option compensation	$ 11	$ 15

Liability-Classified Awards

Performance Share Units. We granted PSUs to senior management that vest ratably over a three-year performance period and are settled in cash. The ultimate amount earned is based on achievement of performance metrics established by the Compensation Committee of the Board of Directors. Compensation expense associated with PSU awards 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 our estimates of the underlying performance measures.

For PSUs granted in 2017 and 2016, performance metrics include a total shareholder return (TSR) component, which can range from 0% to 100% and an operational performance component based on finding and development costs, which can range from 0% to 100%, resulting in a maximum payout of 200%. The payout percentage for the 2016 and 2017 PSU awards is capped at 100% if our absolute TSR is less than zero. The PSUs are settled in cash on the third anniversary of the awards. We utilized a Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs.

Grant Date Assumptions

Assumption	2017 Awards	2016 Awards
Volatility	80.65%	49.74%
Risk-free interest rate	1.54%	1.13%
Dividend yield for value of awards	—%	—%

Reporting Period Assumptions

Assumption	2017 Awards	2016 Awards
Volatility	55.89%	53.77%
Risk-free interest rate	2.23%	2.01%
Dividend yield for value of awards	—%	—%

The PSUs are subsequently adjusted, based on adjustments to the above assumptions through the end of each subsequent reporting period, through the end of the performance period.

For PSUs granted in 2018, performance metrics include an operational performance component based on a ratio of cumulative earnings before interest expense, income taxes, and depreciation, depletion and amortization expense (EBITDA) to capital expenditures, for which payout can range from 0% to 200%. The vested PSUs are settled in cash on each of the three annual vesting dates. We used the closing price of our common stock on the grant date to determine the grant date fair value of the PSUs. The PSUs are subsequently adjusted, based on changes in our stock price through the end of each subsequent reporting period, through the end of the performance period.

Cash Restricted Stock Units. We granted CRSUs to employees that vest straight-line over a three-year period and are settled in cash on each of the three annual vesting dates. The ultimate amount earned is based on the closing price of our common stock on each of the vesting dates. We used the closing price of our common stock on the grant date to determine the grant date fair value of the CRSUs. The CRSUs are subsequently adjusted, based on changes in our stock price through the end of each subsequent reporting period, through the end of each vesting period.

The following table presents a summary of our liability-classified awards:

	Units	Grant Date Fair Value	March 31, 2018	
			Fair Value	Vested Liability
		($ in millions)	($ in millions)	
2018 PSU Awards:				
Payable 2019, 2020 and 2021	4,031,011	$ 12	$ 12	$ —
2017 PSU Awards:				
Payable 2020	1,217,774	$ 8	$ 4	$ 2
2016 PSU Awards:				
Payable 2019	2,348,893	$ 10	$ 8	$ 7
2018 CRSU Awards:				
Payable 2019, 2020 and 2021	16,976,014	$ 52	$ 52	$ —

8. Derivative and Hedging Activities

We use derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility. All of our oil, natural gas and NGL 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 oil, natural gas and NGL derivative instruments were designated for hedge accounting as of March 31, 2018 or December 31, 2017.

Oil, Natural Gas and NGL Derivatives

As of March 31, 2018 and December 31, 2017, our oil, natural gas and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options and call swaptions.
- *Options*: We sell, and occasionally buy, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess on sold call options and we receive 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.
- *Call Swaptions*: We sell call swaptions to counterparties that allow the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- *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, we receive the fixed price and pay the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include the sale by us of an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay 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 March 31, 2018 and December 31, 2017 are provided below:

	March 31, 2018		December 31, 2017	
	Notional Volume	Fair Value ($ in millions)	Notional Volume	Fair Value ($ in millions)
Oil (mmbbl):				
Fixed-price swaps	24	$ (180)	21	$ (151)
Three-way collars	1	(12)	2	(10)
Call swaptions	2	(19)	2	(13)
Basis protection swaps	7	5	11	(9)
Total oil	34	(206)	36	(183)
Natural gas (bcf):				
Fixed-price swaps	358	44	532	149
Three-way collars	88	—	—	—
Collars	36	8	47	11
Call options	93	(1)	110	(3)
Basis protection swaps	41	3	65	(7)
Total natural gas	616	54	754	150
NGL (mmgal):				
Fixed-price swaps	47	—	33	(2)
Total estimated fair value		$ (152)		$ (35)

We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. See further discussion below under *Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)*.

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 March 31, 2018 and December 31, 2017 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in the Consolidated Balance Sheets	Net Fair Value Presented in the Consolidated Balance Sheet
		($ in millions)	
As of March 31, 2018			
Commodity Contracts:			
Short-term derivative asset	$ 60	$ (57)	$ 3
Long-term derivative asset	5	(5)	—
Short-term derivative liability	(206)	57	(149)
Long-term derivative liability	(11)	5	(6)
Total derivatives	$ (152)	$ —	$ (152)
As of December 31, 2017			
Commodity Contracts:			
Short-term derivative asset	$ 157	$ (130)	$ 27
Short-term derivative liability	(188)	130	(58)
Long-term derivative liability	(4)	—	(4)
Total derivatives	$ (35)	$ —	$ (35)

As of March 31, 2018 and December 31, 2017, we did not have any cash collateral balances for our derivatives.

Effect of Derivative Instruments – Condensed Consolidated Statements of Operations

The components of oil, natural gas and NGL revenues for the Current Quarter and the Prior Quarter are presented below:

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
Oil, natural gas and NGL revenues	$ 1,360	$ 1,147
Gains (losses) on undesignated oil, natural gas and NGL derivatives	(107)	332
Losses on terminated cash flow hedges	(10)	(10)
Total oil, natural gas and NGL revenues	$ 1,243	$ 1,469

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

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

	Three Months Ended March 31,			
	2018		2017	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$ (114)	$ (57)	$ (153)	$ (96)
Net change in fair value	—	—	4	4
Losses reclassified to income	10	10	10	10
Balance, end of period	$ (104)	$ (47)	$ (139)	$ (82)

The accumulated other comprehensive loss as of March 31, 2018 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. Remaining deferred gain or loss amounts will be recognized in earnings in the month for which the original contract months are to occur. As of March 31, 2018, we expect to transfer approximately $33 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 highly rated or deemed by us to have acceptable credit strength 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 March 31, 2018, our oil, natural gas and NGL derivative instruments were spread among 11 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, we enter into bilateral hedging agreements with other counterparties. The counterparties' and our obligations under 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.

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 and NGL 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 March 31, 2018 and December 31, 2017:

	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 March 31, 2018				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 53	$ 12	$ 65
Commodity liabilities	—	(181)	(36)	(217)
Total derivatives	$ —	$ (128)	$ (24)	$ (152)
As of December 31, 2017				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ —	$ 8	$ 8
Commodity liabilities	—	(20)	(23)	(43)
Total derivatives	$ —	$ (20)	$ (15)	$ (35)

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

A summary of the changes in the fair values of our financial assets (liabilities) classified as Level 3 during the Current Quarter and the Prior Quarter is presented below:

	Commodity Derivatives
	($ in millions)
Balance, as of January 1, 2018	$ (15)
Total gains (losses) (realized/unrealized):	
Included in earnings[(a)]	(8)
Total purchases, issuances, sales and settlements:	
Settlements	(1)
Balance, as of March 31, 2018	$ (24)
Balance, as of January 1, 2017	$ (10)
Total gains (losses) (realized/unrealized):	
Included in earnings[(a)]	12
Total purchases, issuances, sales and settlements:	
Settlements	1
Balance, as of March 31, 2017	$ 3

(a)

	Commodity Derivatives	
	2018	2017
	($ in millions)	
Total gains (losses) included in earnings for the period	$ (8)	$ 12
Change in unrealized gains (losses) related to assets still held at reporting date	$ (10)	$ 5

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 March 31, 2018:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value March 31, 2018
				($ in millions)
Oil trades	Oil price volatility curves	19.20% – 30.57%	27.29%	$ (31)
Natural gas trades	Natural gas price volatility curves	14.74% – 40.22%	20.73%	$ 7

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 Quarter, we sold portions of our acreage, producing properties and other related property and equipment in the Mid-Continent, including our Mississippian Lime assets, for approximately $420 million, subject to certain customary closing adjustments. Included in the sales were approximately 171,000 net acres and interests in 2,150 wells.

Also, in the Current Quarter, we received proceeds of approximately $18 million, subject to customary closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

In the Prior Quarter, 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 Prior Quarter, we received proceeds of approximately $20 million, net of post-closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

Volumetric Production Payments

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. 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 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. 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.

We have 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 March 31, 2018, we had the following VPP outstanding:

				Volume Sold			
VPP #	Date of VPP	Location	Proceeds	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 remaining to be delivered on behalf of our VPP buyers as of March 31, 2018 were as follows:

		Volume Remaining as of March 31, 2018			
VPP #	**Term Remaining**	**Oil**	**Natural Gas**	**NGL**	**Total**
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	35	0.4	31.3	0.8	38.2

10. Revenue Recognition

The FASB issued *Revenue from Contracts with Customers* (Topic 606) superseding virtually all existing revenue recognition guidance. We adopted this new standard in the first quarter of 2018 using the modified retrospective approach. We applied the new standard to all contracts that were not completed as of January 1, 2018 and reflected the aggregate effect of all modifications in determining and allocating the transaction price. The cumulative effect of adoption of $8 million did not have a material impact on our condensed consolidated financial statements. However, the adoption did result in certain purchase and sale contracts being recorded on a net basis, as an agent, rather than on a gross basis, as principal, due to management's evaluation under new considerations within Topic 606 that indicated we do not have control over the specified commodity in purchase and sale contracts with the same counterparty. Such presentation change did not have an impact on income (loss) from operations, earnings per share or cash flows, but did reduce marketing revenue and marketing expenses in the condensed consolidated financial statements by approximately $115 million for the Current Quarter as compared to what would have been recognized using the revenue recognition guidance that was in affect before the adoption of Topic 606.

In accordance with the new revenue standard requirements, the disclosure of the impact of adoption on our condensed consolidated balance sheet and condensed consolidated statement of operations was as follows:

	Before adoption of ASC 606	Adjustments	As Reported
		($ in millions)	
Balance Sheet as of March 31, 2018			
Other current liabilities	$ 1,355	$ 2	$ 1,357
Other long-term liabilities	$ 339	$ 6	$ 345
Accumulated deficit	$ (16,232)	$ (8)	$ (16,240)
Statement of Operations for the Three Months Ended March 31, 2018			
Marketing revenues	$ 1,361	$ (115)	$ 1,246
Marketing operating expenses	$ 1,383	$ (115)	$ 1,268

Revenue from the sale of oil, natural gas and NGL is recognized upon the transfer of control of the products, which is typically when the products are delivered to customers. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration we expect to receive in exchange for those products.

Revenue from contracts with customers includes the sale of our oil, natural gas and NGL production (recorded as oil, natural gas and NGL revenues in the condensed consolidated statements of operations) as well as the sale of certain of our joint interest holders' production which we purchase under joint operating arrangements (recorded in marketing revenues in the condensed consolidated statements of operations). In connection with the marketing of these products, we obtain control of the oil, natural gas and NGL we purchase from other interest owners at defined delivery points and deliver the product to third parties, at which time revenues are recorded.

Payment terms and conditions vary by contract type, although terms generally include a requirement of payment within 30 days. There are no significant judgments that significantly affect the amount or timing of revenue from contracts with customers.

We also earn revenue from other sources, including from a variety of derivative and hedging activities to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility, (recorded within oil, natural gas and NGL revenues in the condensed consolidated statements of operations) as well as a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including credit risk mitigation and satisfaction of our pipeline delivery commitments (recorded within marketing revenues in the condensed consolidated statements of operations).

In circumstances where we act as an agent rather than a principal, our results of operations related to oil, natural gas and NGL marketing activities are presented on a net basis. These purchase and sales contracts were accounted for as derivatives under *Derivatives and Hedging* (Topic 815) and were not elected as normal purchase or normal sales. We considered the principal versus agent guidance in Topic 606 in determining whether the gains and losses on these derivatives should be reported on a gross or net basis.

The following table shows revenue disaggregated by operating area and product type, for the Current Quarter:

	Three Months Ended March 31, 2018			
	Oil	Natural Gas	NGL	Total
	($ in millions)			
Marcellus	$ —	$ 294	$ —	$ 294
Haynesville	—	210	—	210
Eagle Ford	364	42	40	446
Utica	60	116	52	228
Mid-Continent	73	32	17	122
Powder River Basin	40	12	8	60
Revenue from contracts with customers	537	706	117	1,360
Gains (losses) on oil, natural gas and NGL derivatives	(86)	(32)	1	(117)
Oil, natural gas and NGL revenue	$ 451	$ 674	$ 118	$ 1,243
Marketing revenue from contracts with customers	$ 686	$ 293	$ 110	$ 1,089
Other marketing revenue	117	40	—	157
Marketing revenue	$ 803	$ 333	$ 110	$ 1,246

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL and from exploration and production companies that own interests in properties we operate. This industry concentration could affect our overall exposure to credit risk, either positively or negatively, because our purchasers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and we generally require letters of credit or parent guarantees for receivables from parties deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. We utilize an allowance method in accounting for bad debt based on historical trends in addition to specifically identifying receivables that we believe may be uncollectible. Accounts receivable as of March 31, 2018 and December 31, 2017 are detailed below:

	March 31, 2018	December 31, 2017
	($ in millions)	
Oil, natural gas and NGL sales	$ 829	$ 959
Joint interest	166	209
Other	101	184
Allowance for doubtful accounts	(14)	(30)
Total accounts receivable, net	$ 1,082	$ 1,322

11. Investments

In the Current Quarter, FTS International, Inc. (NYSE: FTSI) completed an initial public offering. Due to the offering, the ownership percentage of our equity method investment in FTSI decreased from approximately 29% to 24% and resulted in a gain of $78 million. In addition, we sold approximately 4.3 million shares of FTSI in the offering for net proceeds of approximately $74 million and recognized a gain of $61 million decreasing our ownership percentage to approximately 20%. We continue to hold approximately 22.0 million shares in the publicly traded company.

12. Other Operating Expenses

In the Prior Quarter, we terminated future natural gas transportation commitments related to divested assets for cash payments of $103 million. In addition, we paid $290 million to assign an oil transportation agreement to a third party.

13. Restructuring and Other Termination Costs

Workforce Reduction

On January 30, 2018, we underwent a reduction in workforce impacting approximately 13% of employees across all functions, primarily on our Oklahoma City campus. In connection with the reduction, we incurred a total charge in the Current Quarter of approximately $38 million for one-time termination benefits. The following table summarizes our restructuring liabilities:

	Other Current Liabilities
	($ in millions)
Balance as of December 31, 2017	$ —
Initial restructuring recognition on January 30, 2018	38
Termination benefits paid	(11)
Balance as of March 31, 2018[(a)]	$ 27

(a) Remaining accrued amounts are expected to be paid by the end of the 2018 second quarter.

14. Fair Value Measurements

Recurring Fair Value Measurements

Other Current Assets. Assets related to our 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 our 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 March 31, 2018 and December 31, 2017:

	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 March 31, 2018				
Financial Assets (Liabilities):				
Other current assets	$ 52	$ —	$ —	$ 52
Other current liabilities	(52)	—	—	(52)
Total	$ —	$ —	$ —	$ —
As of December 31, 2017				
Financial Assets (Liabilities):				
Other current assets	$ 57	$ —	$ —	$ 57
Other current liabilities	(60)	—	—	(60)
Total	$ (3)	$ —	$ —	$ (3)

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.

15. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes, contingent convertible senior notes, term loan and revolving credit facility listed in Note 3 are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries. Subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries are non-guarantors.

The tables below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of March 31, 2018 and December 31, 2017 and for the three months ended March 31, 2018 and 2017. This financial information may not necessarily be indicative of our results of operations, cash flows or financial position had these subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF MARCH 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 34	$ 1	$ 1	$ (32)	$ 4
Other current assets	73	1,147	2	(2)	1,220
Intercompany receivable, net	7,987	29	173	(8,189)	—
Total Current Assets	8,094	1,177	176	(8,223)	1,224
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on full cost accounting, net	478	8,847	27	—	9,352
Other property and equipment, net	—	1,224	—	—	1,224
Property and equipment held for sale, net	—	16	—	—	16
Total Property and Equipment, Net	478	10,087	27	—	10,592
LONG-TERM ASSETS:					
Other long-term assets	49	221	—	—	270
Investments in subsidiaries and intercompany advances	807	77	—	(884)	—
TOTAL ASSETS	$ 9,428	$ 11,562	$ 203	$ (9,107)	$ 12,086
CURRENT LIABILITIES:					
Current liabilities	$ 197	$ 2,188	$ 3	$ (34)	$ 2,354
Intercompany payable, net	28	8,161	—	(8,189)	—
Total Current Liabilities	225	10,349	3	(8,223)	2,354
LONG-TERM LIABILITIES:					
Long-term debt, net	9,325	—	—	—	9,325
Other long-term liabilities	98	406	—	—	504
Total Long-Term Liabilities	9,423	406	—	—	9,829
EQUITY:					
Chesapeake stockholders’ equity (deficit)	(220)	807	77	(884)	(220)
Noncontrolling interests	—	—	123	—	123
Total Equity (Deficit)	(220)	807	200	(884)	(97)
TOTAL LIABILITIES AND EQUITY	$ 9,428	$ 11,562	$ 203	$ (9,107)	$ 12,086

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2017
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 5	$ 1	$ 2	$ (3)	$ 5
Other current assets	154	1,364	3	(1)	1,520
Intercompany receivable, net	8,697	436	—	(9,133)	—
Total Current Assets	8,856	1,801	5	(9,137)	1,525
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on full cost accounting, net	435	8,888	27	—	9,350
Other property and equipment, net	—	1,314	—	—	1,314
Property and equipment held for sale, net	—	16	—	—	16
Total Property and Equipment, Net	435	10,218	27	—	10,680
LONG-TERM ASSETS:					
Other long-term assets	52	168	—	—	220
Investments in subsidiaries and intercompany advances	806	(146)	—	(660)	—
TOTAL ASSETS	$ 10,149	$ 12,041	$ 32	$ (9,797)	$ 12,425
CURRENT LIABILITIES:					
Current liabilities	$ 190	$ 2,168	$ 2	$ (4)	$ 2,356
Intercompany payable, net	433	8,648	52	(9,133)	—
Total Current Liabilities	623	10,816	54	(9,137)	2,356
LONG-TERM LIABILITIES:					
Long-term debt, net	9,921	—	—	—	9,921
Other long-term liabilities	101	419	—	—	520
Total Long-Term Liabilities	10,022	419	—	—	10,441
EQUITY:					
Chesapeake stockholders' equity (deficit)	(496)	806	(146)	(660)	(496)
Noncontrolling interests	—	—	124	—	124
Total Equity (Deficit)	(496)	806	(22)	(660)	(372)
TOTAL LIABILITIES AND EQUITY	$ 10,149	$ 12,041	$ 32	$ (9,797)	$ 12,425

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 1,238	$ 5	$ —	$ 1,243
Marketing	—	1,246	—	—	1,246
Total Revenues	—	2,484	5	—	2,489
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	147	—	—	147
Oil, natural gas and NGL gathering, processing and transportation	—	355	1	—	356
Production taxes	—	31	—	—	31
Marketing	—	1,268	—	—	1,268
General and administrative	—	72	—	—	72
Restructuring and other termination costs	—	38	—	—	38
Provision for legal contingencies, net	—	5	—	—	5
Oil, natural gas and NGL depreciation, depletion and amortization	—	267	1	—	268
Depreciation and amortization of other assets	—	18	—	—	18
Net losses on sales of fixed assets	—	8	—	—	8
Total Operating Expenses	—	2,209	2	—	2,211
INCOME FROM OPERATIONS	—	275	3	—	278
OTHER INCOME (EXPENSE):					
Interest expense	(123)	—	—	—	(123)
Gains on investments	—	139	—	—	139
Equity in net earnings (losses) of subsidiary	416	2	—	(418)	—
Total Other Income (Expense)	293	141	—	(418)	16
INCOME BEFORE INCOME TAXES	293	416	3	(418)	294
INCOME TAX EXPENSE (BENEFIT)	—	—	—	—	—
NET INCOME	293	416	3	(418)	294
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	293	416	2	(418)	293
Other comprehensive income	—	10	—	—	10
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 293	$ 426	$ 2	$ (418)	$ 303

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2017
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 1,463	$ 6	$ —	$ 1,469
Marketing	—	1,284	—	—	1,284
Total Revenues	—	2,747	6	—	2,753
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	135	—	—	135
Oil, natural gas and NGL gathering, processing and transportation	—	353	2	—	355
Production taxes	—	22	—	—	22
Marketing	—	1,328	—	—	1,328
General and administrative	—	64	1	—	65
Provision for legal contingencies, net	—	(2)	—	—	(2)
Oil, natural gas and NGL depreciation, depletion and amortization	—	195	2	—	197
Depreciation and amortization of other assets	—	21	—	—	21
Other operating expenses	—	391	—	—	391
Total Operating Expenses	—	2,507	5	—	2,512
INCOME FROM OPERATIONS	—	240	1	—	241
OTHER INCOME (EXPENSE):					
Interest expense	(95)	—	—	—	(95)
Losses on purchases or exchanges of debt	(7)	—	—	—	(7)
Other income	—	3	—	—	3
Equity in net earnings (losses) of subsidiary	243	—	—	(243)	—
Total Other Income (Expense)	141	3	—	(243)	(99)
INCOME BEFORE INCOME TAXES	141	243	1	(243)	142
INCOME TAX EXPENSE	1	—	—	—	1
NET INCOME	140	243	1	(243)	141
Net income attributable to noncontrolling interests	—	—	(1)	—	(1)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	140	243	—	(243)	140
Other comprehensive income	—	14	—	—	14
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 140	$ 257	$ —	$ (243)	$ 154

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

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
THREE MONTHS ENDED MARCH 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ 78	$ 577	$ 5	$ (4)	$ 656
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(442)	—	—	(442)
Acquisitions of proved and unproved properties	—	(63)	—	—	(63)
Proceeds from divestitures of proved and unproved properties	—	319	—	—	319
Additions to other property and equipment	—	(3)	—	—	(3)
Other investing activities	—	142	—	—	142
Net Cash Used In Investing Activities	—	(47)	—	—	(47)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	2,904	—	—	—	2,904
Payments on revolving credit facility borrowings	(3,485)	—	—	—	(3,485)
Cash paid for preferred stock dividends	(23)	—	—	—	(23)
Other financing activities	25	(2)	(4)	(25)	(6)
Intercompany advances, net	530	(528)	(2)	—	—
Net Cash Used In Financing Activities	(49)	(530)	(6)	(25)	(610)
Net increase (decrease) in cash and cash equivalents	29	—	(1)	(29)	(1)
Cash and cash equivalents, beginning of period	5	1	2	(3)	5
Cash and cash equivalents, end of period	$ 34	$ 1	$ 1	$ (32)	$ 4

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

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
THREE MONTHS ENDED MARCH 31, 2017
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By (Used In) Operating Activities	$ 1	$ 96	$ 4	$ (2)	$ 99
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(433)	—	—	(433)
Acquisitions of proved and unproved properties	—	(95)	—	—	(95)
Proceeds from divestitures of proved and unproved properties	—	892	—	—	892
Additions to other property and equipment	—	(3)	—	—	(3)
Other investing activities	—	19	—	—	19
Net Cash Provided By Investing Activities	—	380	—	—	380
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	50	—	—	—	50
Payments on revolving credit facility borrowings	(50)	—	—	—	(50)
Cash paid to purchase debt	(982)	—	—	—	(982)
Cash paid for preferred stock dividends	(114)	—	—	—	(114)
Other financing activities	(24)	(1)	(3)	12	(16)
Intercompany advances, net	476	(475)	(1)	—	—
Net Cash Provided by (Used In) Financing Activities	(644)	(476)	(4)	12	(1,112)
Net increase (decrease) in cash and cash equivalents	(643)	—	—	10	(633)
Cash and cash equivalents, beginning of period	904	2	1	(25)	882
Cash and cash equivalents, end of period	$ 261	$ 2	$ 1	$ (15)	$ 249

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

Introduction

The following discussion should be read together with the condensed consolidated financial statements included in Item 1 of Part I of this report and our 2017 Form 10-K.

We are an independent exploration and production company engaged in the acquisition, exploration and development of properties for the production of oil, natural gas and NGL from underground reservoirs. We own a large and geographically diverse portfolio of onshore U.S. unconventional natural gas and liquids assets, including interests in approximately 14,500 oil and natural gas wells. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas, the Anadarko Basin in northwestern Oklahoma and the stacked pay in the Powder River Basin in Wyoming. Our natural gas resource plays are the Marcellus Shale in the northern Appalachian Basin in Pennsylvania, the Haynesville/Bossier Shales in northwestern Louisiana and East Texas and the Utica Shale in Ohio.

Our strategy is to create shareholder value through the development of our significant resource plays. We continue to focus on reducing debt, increasing cash provided by operating activities, and improving margins through financial discipline and operating efficiencies. Our capital program is focused on investments that can improve our cash flow generating ability even in a challenging commodity price environment. Although we expect our forecasted capital expenditures in 2018 to be lower compared to 2017, we anticipate modest production growth from both our oil-producing and natural gas-producing assets, adjusted for asset sales. Our ability to reduce capital expenditures while still growing production is primarily the result of improved drilling and completion efficiencies and improved well performance. We continue to seek opportunities to reduce cash costs (production, gathering, processing and transportation, general and administrative and interest expenses) and improve our production volumes from existing wells.

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 us and our shareholders.

In 2018, our focus is concentrated on three strategic priorities:

- reduce total debt by $2 - $3 billion;
- increase net cash provided by operating activities to fund capital expenditures; and
- improve margins through financial discipline and operating efficiencies.

The following discussion and analysis presents management's perspective of our business and material changes to our results of operations for the three-month period ended March 31, 2018 compared to the three-month period ended March 31, 2017 and in our financial condition and liquidity since December 31, 2017.

Overview of Current Quarter

The transformation of Chesapeake over the past four years has been significant and our progress has continued in the Current Quarter. Our basic strategies have not changed through the price cycles of the past several years, and we believe our recent accomplishments and achievements in the Current Quarter have made our company stronger. Our progress has been guided by our strategies of financial discipline, pursuing profitable and efficient growth from our captured resources, leveraging technology and our operational expertise to unlock additional domestic resources and optimizing our portfolio through business development.

We have already made significant progress towards achieving our strategic priorities to date through May 2, 2018. So far we have:

- sold properties in the Mid-Continent, including our Mississippian Lime assets, for aggregate proceeds of approximately $500 million;
- received net proceeds of approximately $74 million from the sale of approximately 4.3 million shares of FTS International, Inc. (NYSE: FTSI). FTSI is a provider of hydraulic fracturing services in North America and a company in which Chesapeake has owned a significant stake since 2006. FTSI completed its initial public offering of common shares on February 6, 2018. We currently own approximately 22.0 million shares of FTSI; and
- reduced our workforce by approximately 13% as part of an overall plan to reduce costs and better align our workforce to the needs of our business, resulting in an expected reduction of annual cash costs of approximately $70 million.

As a result of these events, we have improved our liquidity as of March 31, 2018. In addition, we continue to benefit from progress made over the last four years, including removing financial and operational complexity, significantly improving our balance sheet and addressing numerous legacy issues.

Financial Results

	Three Months Ended March 31,		
	2018	**% Change[c]**	**2017**
		($ in millions)	
Net income available to common stockholders	$ 268	n/m	$ 75
Net earnings per diluted common share	$ 0.29	n/m	$ 0.08
Adjusted production[a] (mboe per day)	540	11 %	485
Total production (mboe per day)	554	5 %	528
Average sales price (per boe)	$ 27.27	13 %	$ 24.13
Oil, natural gas and NGL production expenses	$ 147	9 %	$ 135
Oil, natural gas and NGL gathering, processing and transportation expenses	$ 356	— %	$ 355
General and administrative expenses	$ 72	11 %	$ 65
Total debt (principal amount)[b]	$ 9,400	(6)%	$ 9,981

(a) Adjusted for assets sold.

(b) As of March 31, 2018 and December 31, 2017.

(c) n/m - not meaningful.

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 and has had a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we can 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, our ability to meet financial ratios and covenants in our financing agreements and the availability of lenders' commitments as a result of regulatory pressures in the lending market.

As of March 31, 2018, we had a cash balance of $4 million compared to $5 million as of December 31, 2017, and we had a net working capital deficit of $1.130 billion as of March 31, 2018, compared to a net working capital deficit of $831 million as of December 31, 2017. As of March 31, 2018, we had aggregate total principal amount of debt outstanding of $9.400 billion, compared to $9.981 billion as of December 31, 2017. As of March 31, 2018, we had $3.428 billion of borrowing capacity available under our senior secured revolving credit facility, with outstanding borrowings of $200 million and $157 million utilized for various letters of credit. 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. 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.

Even though we have taken measures to mitigate the liquidity concerns facing us for the next 12 months as outlined above and in *Industry Outlook* in our 2017 Form 10-K, there can be no assurance that these measures will be sufficient for periods beyond the next 12 months. If needed, we may seek to access the capital markets or otherwise refinance a portion of our outstanding indebtedness to improve our liquidity. 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. Furthermore, 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.

Derivative and Hedging Activities

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 market changes, we have entered into various derivative instruments. Our oil, natural gas and NGL derivative activities, when combined with our sales of oil, natural gas and NGL, allow us to better predict the total revenue we expect to receive.

We utilize various oil, natural gas and NGL derivative instruments to protect a portion of our cash flow against downside risk. As of April 27, 2018, we have downside price protection in 2018 and 2019 through the following oil, natural gas and NGL derivative instruments:

Oil Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	% of Forecasted Production (if applicable)	Average NYMEX Price
		(mbbls)		
2018	Swaps	17,110	72%	$53.78
2018	Three-way collars	1,375	6%	$39.15/$47.00/$55.00
2018	Calls	1,840	8%	$52.87
2018	Basis protection swaps	8,159	34%	$3.35
2019	Swaps	11,661	Not disclosed	$57.87

Natural Gas Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	% of Forecasted Production (if applicable)	Average NYMEX Price
		(bcf)		
2018	Swaps	358	57%	$2.95
2018	Two-way collars	36	6%	$3.00/$3.25
2018	Calls	50	8%	$6.27
2018	Basis protection swaps	41	7%	($0.77)
2019	Three-way collars	87	Not disclosed	$2.50/$2.80/$3.10
2019	Basis protection swaps	4	Not disclosed	$2.24
2019	Calls	22	Not disclosed	$12.00
2020	Calls	22	Not disclosed	$12.00

NGL Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	% of Forecasted Production (if applicable)	Average NYMEX Price
		(mmgal)		
2018	Butane swaps	4	5%	$0.88
2018	Butane % of WTI swaps	4	5%	70.5% of WTI
2018	Propane swaps	42	19%	$0.79
2018	Ethane swaps	4	1%	$0.28
2018	Isobutane swaps	10	21%	$0.92
2018	Natural gasoline	33	44%	$1.42

(a) Includes amounts settled in April 2018.

See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of derivatives and hedging activities.

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 March 31, 2018, 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.

Debt

We are committed to decreasing the amount of debt outstanding by $2-3 billion. To accomplish this objective, we intend to allocate our capital expenditures to the highest-return projects, deploy leading drilling and completion technology throughout our portfolio to profitably and efficiently grow, and divest additional large assets to strengthen our cost structure and our portfolio. We are seeking to reduce cash costs (production, gathering, processing and transportation, general and administrative and interest expenses), improve our production volumes from existing wells, and achieve additional operating and capital efficiencies with a focus on growing our oil volumes.

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/or preferred stock through privately negotiated transactions, open market repurchases, redemptions, tender offers or otherwise, but we are under no obligation to do so.

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 next borrowing base redetermination is scheduled for the second quarter of 2018. As of March 31, 2018, we had $3.428 billion of borrowing capacity available under our revolving credit facility. As of March 31, 2018, we had outstanding borrowings of $200 million under the revolving credit facility and had used $157 million of the revolving credit facility for various letters of credit. Borrowings under the facility bear interest at a variable rate. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of this report for further discussion of the terms of the revolving credit facility. As of March 31, 2018, we were in compliance with all applicable financial covenants under the credit agreement. Our first lien secured leverage ratio was approximately 0.15 to 1.00, our interest coverage ratio was approximately 3.28 to 1.00 and our debt to capitalization ratio was approximately 0.37 to 1.00.

Capital Expenditures

Our 2018 capital expenditures program, while planned to be approximately 12% lower than our 2017 program, is expected to generate greater capital efficiency as we focus on expanding our margins by investing in the highest-return projects. 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 2018 capital expenditures, inclusive of capitalized interest, are $2.0 – $2.4 billion compared to our 2017 capital spending level of $2.5 billion. Management continues to review operational plans for 2018 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL.

Credit Risk

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 April 27, 2018, we have received requests and posted approximately $199 million of collateral related to certain of our marketing and other contracts. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $460 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.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Current Quarter and the Prior Quarter. 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.

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
Cash provided by operating activities	$ 656	$ 99
Proceeds from divestitures of proved and unproved properties, net	319	892
Proceeds from sales of other property and equipment, net	68	19
Proceeds from sales of investments	74	—
Total sources of cash and cash equivalents	$ 1,117	$ 1,010

Cash Flow from Operating Activities

Cash provided by operating activities was $656 million in the Current Quarter compared to $99 million in the Prior Quarter. The increase in the Current Quarter is primarily due to the result of higher prices for the oil, natural gas and NGL we sold and higher volumes of oil and natural gas sold, partially offset by increases in certain of our operating expenses. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items, such as depreciation, depletion and amortization, certain 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*.

Uses of Funds

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

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
Oil and Natural Gas Expenditures:		
Drilling and completion costs	$ 442	$ 433
Acquisitions of proved and unproved properties	22	46
Interest capitalized on unproved leasehold	41	49
Total oil and natural gas expenditures	505	528
Other Uses of Cash and Cash Equivalents:		
Payments on revolving credit facility borrowings, net	581	—
Cash paid to repurchase debt	—	982
Additions to other property and equipment	3	3
Dividends paid	23	114
Other	6	16
Total other uses of cash and cash equivalents	613	1,115
Total uses of cash and cash equivalents	$ 1,118	$ 1,643

Oil and Natural Gas Expenditures

Our drilling and completion costs increased in the Current Quarter compared to the Prior Quarter primarily as a result of drilling longer laterals and higher service and supply costs. During the Current Quarter, our average operated rig count was 15 rigs compared to an average operated rig count of 16 rigs in the Prior Quarter and we completed 76 operated wells in the Current Quarter compared to 99 in the Prior Quarter.

Repurchase of Debt

In the Prior Quarter, we used $982 million of cash to repurchase $908 million principal amount of debt.

Dividends

We paid dividends of $23 million on our preferred stock during the Current Quarter and we paid dividends of $114 million on our preferred stock in the Prior Quarter, including $92 million of dividends in arrears that had been suspended throughout 2016. We eliminated common stock dividends in the 2015 third quarter and do not anticipate paying any common stock dividends in the foreseeable future.

Results of Operations

Oil, Natural Gas and NGL Production and Average Sales Prices

	Three Months Ended March 31, 2018								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	873	3.74	—	—	146	26	22.46
Haynesville	—	—	833	2.80	—	—	139	25	16.86
Eagle Ford	61	66.16	141	3.30	18	24.72	102	19	48.22
Utica	11	59.82	440	2.94	23	25.03	107	19	23.39
Mid-Continent	9	62.04	87	2.70	5	26.15	28	5	32.46
Powder River Basin	7	62.86	47	2.82	3	28.77	18	3	37.68
Retained assets[(a)]	88	64.66	2,421	3.19	49	25.24	540	97	27.10
Divested assets	4	63.60	45	2.81	2	30.07	14	3	33.53
Total	92	64.61	2,466	3.18	51	25.45	554	100%	27.27

	Three Months Ended March 31, 2017								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	837	3.01	—	—	139	27	18.04
Haynesville	—	—	682	2.98	—	—	114	22	17.86
Eagle Ford	56	50.90	135	3.40	17	21.38	96	18	38.52
Utica	8	45.42	380	3.50	25	25.65	96	18	24.16
Mid-Continent	7	49.64	92	3.04	6	22.45	28	5	26.73
Powder River Basin	5	49.70	29	3.33	2	25.58	12	2	32.67
Retained assets[(a)]	76	50.16	2,155	3.11	50	23.81	485	92	24.13
Divested assets	8	50.96	187	2.88	4	23.43	43	8	24.06
Total	84	50.24	2,342	3.10	54	23.78	528	100%	24.13

(a) Includes assets retained as of March 31, 2018.

Oil, Natural Gas and NGL Sales

	Three Months Ended March 31,		
	2018	% Change	2017
	($ in millions)		
Oil	$ 537	42%	$ 378
Natural gas	706	8%	653
NGL	117	1%	116
Oil, natural gas and NGL sales	$ 1,360	19%	$ 1,147

The increase in the price received per boe in the Current Quarter resulted in a $156 million increase in revenues, and increased sales volumes resulted in a $57 million increase in revenues, for a total net increase in revenues of $213 million.

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 have resulted in an increase or decrease in Current Quarter revenues and cash flows from operations of approximately $8 million, an increase or decrease of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in Current Quarter revenues and cash flows from operations of approximately $22 million and an increase or decrease of $1.00 per barrel of NGL sold would have resulted in an increase or decrease in Current Quarter revenues and cash flows from operations of approximately $5 million and $4 million, respectively.

Oil, Natural Gas and NGL Derivatives

	Three Months Ended March 31,	
	2018	2017
	($ in millions)	
Oil derivatives – realized gains (losses)	$ (64)	$ 11
Oil derivatives – unrealized gains (losses)	(22)	94
Total gains (losses) on oil derivatives	(86)	105
Natural gas derivatives – realized gains (losses)	67	(16)
Natural gas derivatives – unrealized gains (losses)	(99)	231
Total gains (losses) on natural gas derivatives	(32)	215
NGL derivatives – realized gains (losses)	(1)	1
NGL derivatives – unrealized gains	2	1
Total gains (losses) on NGL derivatives	1	2
Total gains (losses) on oil, natural gas and NGL derivatives	$ (117)	$ 322

See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of this report for a discussion of our derivative activity.

Marketing Revenues and Expenses

Marketing revenues primarily consist of marketing services, including commodity price structuring, securing and negotiating gathering, hauling, processing and transportation services, contract administration and nomination services for Chesapeake and other interest owners in Chesapeake-operated wells. Expenses related to our marketing 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.

	Three Months Ended March 31,		
	2018	% Change	2017
		($ in millions)	
Marketing revenues	$ 1,246	(3)%	$ 1,284
Marketing expenses	1,268	(5)%	1,328
Marketing gross margin	$ (22)	50 %	$ (44)

Gross margin increased primarily as a result of increased oil, natural gas and NGL prices received in our marketing operations.

Oil, Natural Gas and NGL Production Expenses

	Three Months Ended March 31,		
	2018	% Change	2017
Oil, natural gas and NGL production expenses		($ in millions)	
Marcellus	$ 8	60 %	$ 5
Haynesville	16	60 %	10
Eagle Ford	48	14 %	42
Utica	11	22 %	9
Mid-Continent	29	— %	29
Powder River Basin	12	71 %	7
Retained Assets[a]	124	22 %	102
Divested Assets	11	(45)%	20
Total	135	11 %	122
Ad valorem tax[b]	12	(8)%	13
Total oil, natural gas and NGL production expenses	$ 147	9 %	$ 135
Oil, natural gas and NGL production expenses		($ per boe)	
Marcellus	$ 0.62	63 %	$ 0.38
Haynesville	$ 1.28	35 %	$ 0.95
Eagle Ford	$ 5.17	7 %	$ 4.84
Utica	$ 1.19	16 %	$ 1.03
Mid-Continent	$ 11.36	(1)%	$ 11.46
Powder River Basin	$ 7.17	5 %	$ 6.86
Retained Assets[a]	$ 2.55	10 %	$ 2.32
Divested Assets	$ 8.44	64 %	$ 5.15
Total	$ 2.69	5 %	$ 2.55
Ad valorem tax[b]	$ 0.25	(14)%	$ 0.29
Total oil, natural gas and NGL production expenses per boe	$ 2.94	4 %	$ 2.84

(a) Includes assets retained as of March 31, 2018.

(b) Excludes ad valorem tax expense on divested assets.

The absolute and per unit increase was the result of increased saltwater disposal costs in all operating areas, increased workover activity primarily in Haynesville and Powder River Basin, and increased repairs and maintenance in the Eagle Ford.

Production expenses in the Current Quarter and the Prior Quarter included approximately $4 million and $6 million associated with VPP production volumes, respectively. 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

	Three Months Ended March 31,	
	2018	2017
	($ in millions, except per unit)	
Oil, natural gas and NGL gathering, processing and transportation expenses	$ 356	$ 355
Oil ($ per bbl)	$ 4.18	$ 3.85
Natural gas ($ per mcf)	$ 1.27	$ 1.35
NGL ($ per bbl)	$ 8.83	$ 8.47
Total ($ per boe)	$ 7.15	$ 7.47

Production Taxes

	Three Months Ended March 31,		
	2018	% Change	2017
	($ in millions, except per unit)		
Production taxes	$ 31	41%	$ 22
Production taxes per boe	$ 0.62	32%	$ 0.47

The absolute and per unit increase in production taxes was primarily due to higher prices received for our oil, natural gas and NGL production.

General and Administrative Expenses

	Three Months Ended March 31,		
	2018	% Change	2017
	($ in millions, except per unit)		
Gross overhead	$ 188	(6)%	$ 201
Allocated to production expenses	(40)	(11)%	(45)
Allocated to marketing expenses	(6)	(25)%	(8)
Capitalized	(32)	(11)%	(36)
Reimbursed from third parties	(38)	(19)%	(47)
General and administrative expenses, net	$ 72	11 %	$ 65
General and administrative expenses, net per boe	$ 1.44	7 %	$ 1.35

Gross overhead decreased primarily due to lower compensation costs. The absolute and per unit net expense increase was primarily due to less overhead allocated to production expenses, marketing expenses and capitalized general and administrative costs, as well as less overhead billed to third party working interest owners, due to certain divestitures in 2017.

Restructuring and Other Termination Costs

On January 30, 2018, we underwent a reduction in workforce impacting approximately 13% of employees across all functions, primarily on our Oklahoma City campus. In connection with the reduction, we incurred a total charge of approximately $38 million in the Current Quarter for one-time termination benefits. The charge consisted of $33 million in salary expense and $5 million of other termination benefits.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization

	Three Months Ended March 31,		
	2018	% Change	2017
	($ in millions, except per unit)		
Oil, natural gas and NGL depreciation, depletion and amortization	$ 268	36%	$ 197
Oil, natural gas and NGL depreciation, depletion and amortization per boe	$ 5.38	30%	$ 4.15

The absolute increase is primarily driven by a higher depletion rate per boe coupled with an increase in production. The depletion rate per boe is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented. The increase in depletion rate per boe primarily reflects a downward revision in proved reserves estimates in 2017 due to an updated development plan in the Eagle Ford aligning up-spacing, our activity schedule and well performance. The downward revision in proved reserves was partially offset by the effect of upward price revisions as a result of improved oil, natural gas and NGL prices.

Depreciation and Amortization of Other Assets

	Three Months Ended March 31,		
	2018	% Change	2017
	($ in millions, except per unit)		
Depreciation and amortization of other assets	$ 18	(14)%	$ 21
Depreciation and amortization of other assets per boe	$ 0.36	(18)%	$ 0.44

The absolute and per unit decrease was primarily the result of the sale of other assets.

Other Operating Expense

	Three Months Ended March 31,		
	2018	% Change	2017
	($ in millions)		
Other operating expense	$ —	(100)%	$ 391

In the Prior Quarter, we paid $290 million to assign an oil transportation agreement to a third party. In addition, we terminated future natural gas gathering transportation commitments related to divested assets for a cash payment of $103 million.

Interest Expense

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	($ in millions)	
Interest expense on senior notes	$ 144	$ 136
Interest expense on term loan	28	32
Amortization of loan discount, issuance costs and other	8	9
Amortization of premium	(24)	(41)
Interest expense on revolving credit facility	10	9
Realized gains on interest rate derivatives[(a)]	(1)	(1)
Unrealized (gains) losses on interest rate derivatives[(b)]	1	2
Capitalized interest	(43)	(51)
Total interest expense	$ 123	$ 95
Average senior notes borrowings	$ 7,967	$ 7,689
Average credit facilities borrowings	$ 598	$ —
Average term loan borrowings	$ 1,233	$ 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 increase in interest expense is primarily due to a decrease in amortization of premium and capitalized interest. The decrease in amortization of premium is due to the decrease in the average outstanding principal amount of the 8% second lien notes. The decrease in capitalized interest is a result of lower average balances of unproved oil and natural gas properties, the primary asset on which interest is capitalized. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of this report for a discussion of our debt refinancing. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $2.45 per boe in the Current Quarter compared to $1.97 per boe in the Prior Quarter.

Losses on Purchases or Exchanges of Debt

In the Prior Quarter, we retired $908 million principal amount of our outstanding senior notes and contingent convertible notes through purchases in the open market, tender offers or repayment upon maturity for $982 million, which included the maturity of our 6.25% Euro-denominated Senior Notes due 2017 and the corresponding cross currency swap. We recorded an aggregate net loss of approximately $7 million associated with the repurchases and tender offers.

Income Tax Expense

We recorded no income tax expense in the Current Quarter and recorded $1 million of income tax expense in the Prior Quarter. Our effective income tax rate was 0.0% in the Current Quarter compared to 0.7% in the Prior Quarter. For the Current Quarter, our effective tax rate remains nominal as a result of maintaining a valuation allowance against substantially all of our net deferred tax asset. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. See Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of income tax expense.

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 include our current expectations or forecasts of future events, including our ability to meet debt service requirements and the Introduction to Item 2 of this report. In this context, forward-looking statements often address our expected future business, financial performance and financial condition, and often contain words such as "expect," “could,” “may,” "anticipate," "intend," "plan," “ability,” "believe," "seek," "see," "will," "would," “estimate,” “forecast,” "target," “guidance,” “outlook,” “opportunity” or “strategy.”

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause our actual results to be materially different than those expressed in our forward-looking statements include:

- the volatility of oil, natural gas and NGL prices;
- 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 replace reserves and sustain production;
- drilling and operating risks and resulting liabilities;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- 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;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- effects of environmental protection laws and regulation on our business;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- effects of acquisitions and dispositions; and
- other factors that are described under *Risk Factors* in Item 1A of our 2017 Form 10-K.

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. 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. Our oil, natural gas and NGL derivative activities, when combined with our sales of oil, natural gas and NGL, allow us to predict with greater certainty the revenue we will receive. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse oil, natural gas and NGL price changes is to hedge into strengthening oil, natural gas and NGL 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. Executive management is involved in our risk management activities and the Board of Directors reviews our derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading.

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 notional 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 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 us are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the fair value measurements associated with our derivatives.

As of March 31, 2018, our oil, natural gas and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options and call swaptions.
- *Options*: We sell, and occasionally buy, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess on sold call options, and we receive 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.
- *Call Swaptions*: We sell call swaptions to counterparties that allow the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time
- *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, we receive the fixed price and pay the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include the sale by us of an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty’s downside exposure below the second put option strike price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay the floating market price differential to the counterparty for the hedged commodity.

As of March 31, 2018, we had the following open oil, natural gas and NGL derivative instruments:

	Volume	Weighted Average Price: Fixed	Call	Put	Differential	Fair Value Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps:						
Short-term	18	$ 53.46	$ —	$ —	$ —	$ (172)
Long-term	6	$ 56.84	$ —	$ —	$ —	(8)
Three Way Collars:						
Short-term	1	$ —	$ 55.00	$39.15/$47.00	$ —	$ (12)
Call Swaptions:						
Short-term	2	$ 52.87	$ —	$ —	$ —	$ (19)
Basis Protection Swaps:						
Short-term	7	$ —	$ —	$ —	$ 3.38	5
Total Oil						(206)
	(bcf)	($ per mcf)				
Natural Gas:						
Swaps[(a)]:						
Short-term	358	$ 2.95	$ —	$ —	$ —	44
Three Way Collars:						
Short-term	22	—	$ 3.10	$2.50/$2.80	—	(1)
Long-term	66	—	$ 3.10	$2.50/$2.80	—	1
Collars:						
Short-term	36	$ —	$ 3.25	$ 3.00	$ —	8
Call Options (sold):						
Short-term	55	$ —	$ 6.83	$ —	$ —	(1)
Long-term	38	$ —	$ 12.00	$ —	$ —	—
Basis Protection Swaps:						
Short-term	41	$ —	$ —	$ —	$ (0.77)	3
Total Natural Gas						54
	(mmgal)	($ per gal)				
NGL:						
Propane Swaps						
Short-term	12	$ 0.73	$ —	$ —	$ —	(1)
Butane Swaps						
Short-term	4	$ 0.88	$ —	$ —	$ —	—
Short-term % of WTI	4	70.5%	$ —	$ —	$ —	1
Ethane Swaps						
Short-term	4	$ 0.28	$ —	$ —	$ —	—
Natural Gasoline Swaps						
Short-term	23	$ 1.42	$ —	$ —	$ —	—
Total NGL						—
Total Estimated Fair Value						$ (152)

(a) This amount includes a sold option to enhance the swap price at an average price of $3.40/mcf covering 33 bcf, included in the sold call options.

In addition to the open derivative positions disclosed above, as of March 31, 2018, we had $74 million of net derivative losses related to settled contracts for future periods that will be recorded within oil, natural gas and NGL revenues 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 specified in the original contract as noted below:

	March 31, 2018
	($ in millions)
Short-term	$ (24)
Long-term	(50)
Total	$ (74)

The table below reconciles the changes in fair value of our oil and natural gas derivatives during the Current Quarter. Of the $152 million fair value liability as of March 31, 2018, a $146 million liability relates to contracts maturing in the next 12 months and a $6 million liability relates to contracts maturing after 12 months. All open derivative instruments as of March 31, 2018 are expected to mature by December 31, 2020.

	March 31, 2018
	($ in millions)
Fair value of contracts outstanding, as of January 1, 2018	$ (35)
Change in fair value of contracts	(126)
Contracts realized or otherwise settled	9
Fair value of contracts outstanding, as of March 31, 2018	$ (152)

Interest Rate Risk

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.

	Years of Maturity						
	2018	2019	2020	2021	2022	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate	$ 53	$ —	$ 664	$ 815	$ 1,867	$ 4,188	$ 7,587
Average interest rate	6.42%	—%	6.71%	5.88%	7.25%	7.07%	6.95%
Debt – variable rate	$ —	$ 580	$ —	$ 1,233	$ —	$ —	$ 1,813
Average interest rate	—%	4.70%	—%	8.95%	—%	—%	7.60%

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.

As of March 31, 2018, we had $7 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.

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 Securities Exchange Act of 1934, as amended (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 our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded as of March 31, 2018 that our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended March 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. *Legal Proceedings*

There have been no material developments in previously reported legal or environmental proceedings except for the items discussed below. For a description of certain legal and regulatory proceedings affecting us, see “Contingencies and Commitments,” Note 4 to the Consolidated Financial Statements included in Item 1 of Part 1 of this report and Item 3 in our 2017 Form 10-K.

Regulatory and Related Proceedings. We have previously disclosed receiving U.S. Postal Service and state subpoenas seeking information on our royalty payment practices. The U.S. Postal Service inquiry and all outstanding state subpoenas have been resolved.

We have also previously disclosed 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 us 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. On April 12, 2018, we reached a tentative settlement to resolve substantially all Oklahoma civil class action antitrust cases for an immaterial amount.

We recently received a demand letter from the Healthcare of Ontario Pension Plan (HOOPP) regarding HOOPP’s purchase of our interest in Chaparral Energy, Inc. stock for $215 million on January 5, 2014. HOOPP claims that we engaged in material misrepresentations and fraud, and that we violated the Exchange Act and Oklahoma Uniform Securities Act. HOOPP seeks $215 million in monetary damages, plus interest, attorney’s fees, disgorgement and punitive damages. We expect a lawsuit will be filed, and we intend to vigorously defend it.

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 2017 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

The following table presents information about repurchases of our common stock during the quarter ended March 31, 2018:

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)
January 1, 2018 through January 31, 2018	12,101	$ 4.11	—	$ 1,000
February 1, 2018 through February 28, 2018	1,439,377	$ 2.88	—	$ 1,000
March 1, 2018 through March 31, 2018	—	$ —	—	$ 1,000
Total	1,451,478	$ 2.89	—	

(a) Includes shares of common stock purchased on behalf of our deferred compensation plan related to Company matching contributions.

(b) In December 2014, our 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 March 31, 2018, there have been no repurchases under the program.

ITEM 3. *Defaults Upon Senior Securities*

None.

ITEM 4. *Mine Safety Disclosures*

Not applicable.

ITEM 5. *Other Information*

None.

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				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed or Furnished Herewith**
3.1.1	Chesapeake's Restated Certificate of Incorporation.	10-Q	001-13726	3.1.1	8/3/2017	
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	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
31.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	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	XBRL Taxonomy Extension Presentation Linkbase Document.					X

Signatures

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

CHESAPEAKE ENERGY CORPORATION

Date: May 2, 2018	By:	/s/ ROBERT D. LAWLER Robert D. Lawler President and Chief Executive Officer
Date: May 2, 2018	By:	/s/ DOMENIC J. DELL'OSSO, JR. Domenic J. Dell'Osso, Jr. Executive Vice President and Chief Financial Officer

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

RATIOS OF EARNINGS TO FIXED CHARGES AND COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS

	Years Ended December 31,					Three Months Ended March 31,
	2013	2014	2015	2016	2017	2018
EARNINGS:						
Income (loss) before income taxes and cumulative effect of accounting change	$ 1,442	$ 3,200	$ (19,098)	$ (4,589)	$ 954	$ 293
Interest expense[(a)]	207	172	322	275	421	122
Loss on investment in equity investees in excess of distributed earnings	219	75	96	8	—	—
Amortization of capitalized interest	440	438	483	729	487	105
Loan cost amortization	37	32	31	24	25	6
Less: (Income) loss attributable to noncontrolling interests			68	9	(4)	(1)
Earnings (losses)	$ 2,345	$ 3,917	$ (18,098)	$ (3,544)	$ 1,883	$ 525
FIXED CHARGES:						
Interest Expense	$ 207	$ 172	$ 322	$ 275	$ 421	$ 122
Capitalized interest	815	604	410	242	193	43
Loan cost amortization	37	32	31	24	25	6
Fixed Charges	$ 1,059	$ 808	$ 763	$ 541	$ 639	$ 171
PREFERRED STOCK DIVIDENDS:						
Preferred dividend requirements	$ 171	$ 171	$ 171	$ 97	$ 84	$ 23
Ratio of income (loss) before provision for taxes to net income (loss)[(b)]	1.61	1.56	1.30	1.04	1.00	1.00
Preferred Dividends	$ 275	$ 266	$ 222	$ 101	$ 84	$ 23
COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS	$ 1,334	$ 1,074	$ 985	$ 642	$ 723	$ 194
RATIO OF EARNINGS TO FIXED CHARGES	2.2	4.8	—	—	2.9	3.1
INSUFFICIENT COVERAGE	$ —	$ —	$ 18,861	$ 4,085	$ —	$ —
RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS	1.8	3.6	—	—	2.6	2.7
INSUFFICIENT COVERAGE	$ —	$ —	$ 19,083	$ 4,186	$ —	$ —

(a) Excludes the effect of unrealized gains or losses on interest rate derivatives and includes amortization of bond discount.

(b) Amounts of income (loss) before provision for taxes and of net income (loss) exclude the cumulative effect of accounting change.

Exhibit 31.1

CERTIFICATION

I, Robert D. Lawler, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Chesapeake Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 2, 2018

By: /s/ ROBERT D. LAWLER
Robert D. Lawler
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Domenic J. Dell'Osso, Jr., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Chesapeake Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 2, 2018

By: /s/ DOMENIC J. DELL'OSSO, JR.
Domenic J. Dell'Osso, Jr.
Executive Vice President and Chief Financial Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Chesapeake Energy Corporation (the “Company”) on Form 10-Q for the period ended March 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert D. Lawler, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

May 2, 2018

By: /s/ ROBERT D. LAWLER
Robert D. Lawler
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Chesapeake Energy Corporation (the “Company”) on Form 10-Q for the quarter ended March 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Domenic J. Dell’Osso, Jr., Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

May 2, 2018

By: /s/ DOMENIC J. DELL’OSSO, JR.
Domenic J. Dell’Osso, Jr.
Executive Vice President and
Chief Financial Officer