CHESAPEAKE ENERGY CORP
Form 10-Q
August 01, 2018

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended June 30, 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 every Interactive Data File required to be submitted 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 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 July 25, 2018, there were 912,274,017 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
INDEX TO FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2018


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June 30, 2018 and 2017
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PART I. FINANCIAL INFORMATION

ITEM 1. Condensed Consolidated Financial Statements

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

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| | ($ in millions) | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents ($2 and $2 attributable to our VIE) | $3 | $5 |
| Accounts receivable, net | 1,060 | 1,322 |
| Short-term derivative assets | — | 27 |
| Other current assets | 177 | 171 |
| Total Current Assets | 1,240 | 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) | 69,976 | 68,858 |
| Unproved properties | 3,226 | 3,484 |
| Other property and equipment | 1,822 | 1,986 |
| Total Property and Equipment, at Cost | 75,024 | 74,328 |
| Less: accumulated depreciation, depletion and amortization (($463) and ($461) attributable to our VIE) | (64,185 ) | (63,664 ) |
| Property and equipment held for sale, net | 11 | 16 |
| Total Property and Equipment, Net | 10,850 | 10,680 |
| LONG-TERM ASSETS: | | |
| Other long-term assets | 251 | 220 |
| TOTAL ASSETS | $12,341 | $12,425 |

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

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| | ($ in millions) | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $742 | $654 |
| Current maturities of long-term debt, net | 432 | 52 |
| Accrued interest | 125 | 137 |
| Short-term derivative liabilities | 297 | 58 |
| Other current liabilities ($2 and $3 attributable to our VIE) | 1,277 | 1,455 |
| Total Current Liabilities | 2,873 | 2,356 |
| LONG-TERM LIABILITIES: | | |
| Long-term debt, net | 9,238 | 9,921 |
| Long-term derivative liabilities | 21 | 4 |
| Asset retirement obligations, net of current portion | 149 | 162 |
| Other long-term liabilities | 177 | 354 |
| Total Long-Term Liabilities | 9,585 | 10,441 |
| CONTINGENCIES AND COMMITMENTS (Note 4) | | |
| EQUITY: | | |
| Chesapeake Stockholders' Equity (Deficit): | | |
| 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: 913,271,035 and 908,732,809 shares issued | 9 | 9 |
| Additional paid-in capital | 14,408 | 14,437 |
| Accumulated deficit | (16,257) | (16,525) |
| Accumulated other comprehensive loss | (40) | (57) |
| Less: treasury stock, at cost; 3,319,061 and 2,240,394 common shares | (31) | (31) |
| Total Chesapeake Stockholders' Equity (Deficit) | (240) | (496) |
| Noncontrolling interests | 123 | 124 |
| Total Equity (Deficit) | (117) | (372) |
| TOTAL LIABILITIES AND EQUITY | $12,341 | $12,425 |

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

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | ($ in millions except per share data) | | | |
| REVENUES: | | | | |
| Oil, natural gas and NGL | $982 | $1,279 | $2,225 | $2,748 |
| Marketing | 1,273 | 1,002 | 2,519 | 2,286 |
| Total Revenues | 2,255 | 2,281 | 4,744 | 5,034 |
| OPERATING EXPENSES: | | | | |
| Oil, natural gas and NGL production | 138 | 140 | 285 | 275 |
| Oil, natural gas and NGL gathering, processing and transportation | 340 | 357 | 696 | 712 |
| Production taxes | 26 | 21 | 57 | 43 |
| Marketing | 1,292 | 1,027 | 2,560 | 2,355 |
| General and administrative | 91 | 70 | 163 | 135 |
| Restructuring and other termination costs | — | — | 38 | — |
| Provision for legal contingencies, net | 4 | 17 | 9 | 15 |
| Oil, natural gas and NGL depreciation, depletion and amortization | 271 | 202 | 539 | 399 |
| Depreciation and amortization of other assets | 19 | 21 | 37 | 42 |
| Impairments | 46 | — | 46 | — |
| Other operating (income) expense | (1) | 26 | (1) | 417 |
| Net (gains) losses on sales of fixed assets | (1) | 1 | 7 | 1 |
| Total Operating Expenses | 2,225 | 1,882 | 4,436 | 4,394 |
| INCOME FROM OPERATIONS | 30 | 399 | 308 | 640 |
| OTHER INCOME (EXPENSE): | | | | |
| Interest expense | (117) | (93) | (240) | (188) |
| Gains on investments | — | — | 139 | — |
| Gains on purchases or exchanges of debt | — | 191 | — | 184 |
| Other income (expense) | 62 | (1) | 62 | 2 |
| Total Other Income (Expense) | (55) | 97 | (39) | (2) |
| INCOME (LOSS) BEFORE INCOME TAXES | (25) | 496 | 269 | 638 |
| Income tax expense (benefit) | (9) | 1 | (9) | 2 |
| NET INCOME (LOSS) | (16) | 495 | 278 | 636 |
| Net income attributable to noncontrolling interests | (1) | (1) | (2) | (2) |
| NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE | (17) | 494 | 276 | 634 |
| Preferred stock dividends | (23) | (16) | (46) | (39) |
| Loss on exchange of preferred stock | — | — | — | (41) |
| Earnings allocated to participating securities | — | (8) | (2) | (7) |
| NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS | $(40) | $470 | $228 | $547 |
| EARNINGS (LOSS) PER COMMON SHARE: | | | | |
| Basic | $(0.04) | $0.52 | $0.25 | $0.60 |
| Diluted | $(0.04) | $0.47 | $0.25 | $0.59 |
| WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions): | | | | |

| | | | | |
|---|---|---|---|---|
| Basic | 909 | 908 | 908 | 907 |
| Diluted | 909 | 1,114 | 908 | 1,053 |

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | ($ in millions) | | | |
| NET INCOME (LOSS) | $(16) | $495 | $278 | $636 |
| OTHER COMPREHENSIVE INCOME, NET OF INCOME TAX: | | | | |
| Unrealized gains on derivative instruments[a] | — | — | — | 4 |
| Reclassification of losses on settled derivative instruments[a] | 7 | 7 | 17 | 17 |
| Other Comprehensive Income | 7 | 7 | 17 | 21 |
| COMPREHENSIVE INCOME (LOSS) | (9 ) | 502 | 295 | 657 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS | (1 ) | (1 ) | (2 ) | (2 ) |
| COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE | $(10) | $501 | $293 | $655 |

(a) Deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.

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

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

| | Six Months Ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| | ($ in millions) | |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| NET INCOME | $278 | $636 |
| ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES: | | |
| Depreciation, depletion and amortization | 576 | 441 |
| Derivative (gains) losses, net | 368 | (522) |
| Cash payments on derivative settlements, net | (55) | (66) |
| Stock-based compensation | 18 | 27 |
| Net losses on sales of fixed assets | 7 | 1 |
| Impairments | 46 | — |
| Gains on investments | (139) | — |
| Gains on purchases or exchanges of debt | — | (185) |
| Other | (102) | (43) |
| Changes in assets and liabilities | 94 | (347) |
| Net Cash Provided By (Used In) Operating Activities | 1,091 | (58) |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Drilling and completion costs | (979) | (1,031) |
| Acquisitions of proved and unproved properties | (191) | (162) |
| Proceeds from divestitures of proved and unproved properties | 384 | 951 |
| Additions to other property and equipment | (5) | (7) |
| Proceeds from sales of other property and equipment | 74 | 26 |
| Proceeds from sales of investments | 74 | — |
| Net Cash Used In Investing Activities | (643) | (223) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Proceeds from revolving credit facility borrowings | 6,118 | 2,551 |
| Payments on revolving credit facility borrowings | (6,393) | (1,976) |
| Proceeds from issuance of senior notes, net | — | 742 |
| Extinguishment of other financing | (122) | — |
| Cash paid to purchase debt | — | (1,746) |
| Cash paid for preferred stock dividends | (46) | (137) |
| Distributions to noncontrolling interest owners | (3) | (5) |
| Other | (4) | (17) |
| Net Cash Used In Financing Activities | (450) | (588) |
| Net decrease in cash and cash equivalents | (2) | (869) |
| Cash and cash equivalents, beginning of period | 5 | 882 |
| Cash and cash equivalents, end of period | $3 | $13 |

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

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

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

| | Six Months Ended June 30, 2018 | 2017 |
|---|---|---|
| | ($ in millions) | |
| SUPPLEMENTAL CASH FLOW INFORMATION: | | |
| Interest paid, net of capitalized interest | $276 | $217 |
| Income taxes paid, net of refunds received | $(7 ) | $(14 ) |
| SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES: | | |
| Change in accrued drilling and completion costs | $109 | $87 |
| Change in accrued acquisitions of proved and unproved properties | $1 | $4 |
| Change in divested proved and unproved properties | $(21 ) | $16 |

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

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

| | Six Months Ended June 30, | |
|---|---|---|
| | 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 | 17 | 29 |
| 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 | (46) | (137) |
| Balance, end of period | 14,408 | 14,458 |
| RETAINED EARNINGS (ACCUMULATED DEFICIT): | | |
| Balance, beginning of period | (16,525) | (17,603) |
| Net income attributable to Chesapeake | 276 | 634 |
| Cumulative effect of accounting change | (8) | — |
| Balance, end of period | (16,257) | (16,969) |
| ACCUMULATED OTHER COMPREHENSIVE LOSS: | | |
| Balance, beginning of period | (57) | (96) |
| Hedging activity | 17 | 21 |
| Balance, end of period | (40) | (75) |
| TREASURY STOCK – COMMON: | | |
| Balance, beginning of period | (31) | (27) |
| Purchase of 1,468,524 and 1,189,813 shares for company benefit plans | (4) | (6) |
| Release of 389,857 and 73,990 shares from company benefit plans | 4 | 1 |
| Balance, end of period | (31) | (32) |
| TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT) | (240) | (938) |
| NONCONTROLLING INTERESTS: | | |
| Balance, beginning of period | 124 | 257 |
| Net income attributable to noncontrolling interests | 2 | 2 |
| Distributions to noncontrolling interest owners | (3) | (5) |
| Balance, end of period | 123 | 254 |
| TOTAL EQUITY (DEFICIT) | $(117) | $(684) |

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

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

1. Basis of Presentation
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 and six months ended June 30, 2018 (the “Current Quarter” and the “Current Period”, respectively) and the three and six months ended June 30, 2017 (the “Prior Quarter” and the “Prior Period”, respectively). 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 tax reform legislation known as the Tax Cuts and Jobs Act of 2017 (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. Using the revised framework, we have completed our assessment of lease categories that we believe will be affected by the new standard. We are continuing to assess the accounting treatment for these leases and the resulting impacts to our consolidated financial statements and related disclosures.

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

2. Earnings Per Share

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

Diluted EPS is calculated assuming the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For 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 is as follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | (in millions, except per share data) | | | |
| Net income (loss) available to common stockholders | $(40) | $470 | $228 | $547 |
| Effect of dilutive securities | — | 59 | — | 72 |
| Diluted income (loss) available to common stockholders | $(40) | $529 | $228 | $619 |
| | | | | |
| Weighted average common and common equivalent shares outstanding - basic | 909 | 908 | 908 | 907 |
| Effect of dilutive securities | — | 206 | — | 146 |
| Weighted average common and common equivalent shares outstanding - diluted | 909 | 1,114 | 908 | 1,053 |
| | | | | |
| Net income per share attributable to Chesapeake: | | | | |
| Basic | $(0.04) | $0.52 | $0.25 | $0.60 |
| Diluted | $(0.04) | $0.47 | $0.25 | $0.59 |
| | | | | |
| Shares of common stock for the following securities were excluded from the calculation of diluted EPS as the effect was antidilutive: | | | | |
| Common stock equivalent of our preferred stock outstanding | 60 | — | 60 | 60 |
| Common stock equivalent of our convertible senior notes outstanding | 146 | — | 146 | — |
| Common stock equivalent of our preferred stock outstanding prior to exchange | — | — | — | 1 |
| Participating securities | 1 | 1 | 1 | 1 |

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

3. Debt

Our long-term debt consisted of the following as of June 30, 2018 and December 31, 2017:

| | June 30, 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 | 1,847 | 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 | 852 | 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 | 506 | 506 | 781 | 781 |
| Debt issuance costs | — | (57) | — | (63) |
| Interest rate derivatives | — | 1 | — | 2 |
| Total debt, net | 9,706 | 9,670 | 9,981 | 9,973 |
| Less current maturities of long-term debt, net[c] | (433) | (432) | (53) | (52) |
| Total long-term debt, net | $9,273 | $9,238 | $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 Current Quarter, 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 third quarter of 2018.

(c) As of June 30, 2018, current maturities of long-term debt, net includes our 7.25% Senior Notes due December 2018, our Floating Rate Senior Notes due April 2019, and due to the holders' put option, our 2.25% Contingent Convertible Notes due December 2038.

Debt Retirements

In the Prior Period, we retired $1.604 billion principal amount of our outstanding senior notes, senior secured second lien notes and contingent convertible notes through purchases in the open market, tender offers or repayment upon maturity for $1.746 billion. For the open market repurchases and tender offers, we recorded aggregate net gains of approximately $191 million and $184 million in the Prior Quarter and the Prior Period, respectively.

Revolving Credit Facility

We have a senior secured revolving credit facility currently subject to a $3.8 billion borrowing base that matures in December 2019. As of June 30, 2018, we had outstanding borrowings of $506 million under the revolving credit facility and had used $183 million of the revolving credit facility for various letters of credit. Borrowings under the revolving credit facility bear interest at a variable rate. In the Current Quarter, we completed a scheduled borrowing base redetermination review and our lenders reaffirmed our $3.8 billion borrowing base. Our next scheduled borrowing base redetermination is scheduled for the fourth quarter of 2018.

Our revolving credit facility is subject to various financial and other covenants. 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. As of June 30, 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:

| | June 30, 2018 | | December 31, 2017 | |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| | ($ in millions) | | | |
| Short-term debt (Level 1) | $432 | $432 | $52 | $ 53 |
| Long-term debt (Level 1) | $2,256 | $2,261 | $2,633 | $ 2,629 |
| Long-term debt (Level 2) | $6,982 | $7,215 | $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 such 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.

On July 28, 2017, OOGC America LLC (OOGC) filed a demand for arbitration with the American Arbitration Association against Chesapeake Exploration, L.L.C., our wholly owned subsidiary, in connection with OOGC’s purchase of certain oil and gas leases and other assets pursuant to a Purchase and Sale Agreement entered into on October 10, 2010. In connection with the sale, we also entered into a Development Agreement with OOGC, dated November 15, 2010 (the "Development Agreement"), which governs each of our rights and obligations with respect to the sale, including the transportation and marketing of oil and gas. OOGC's breach of contract, breach of agency and fiduciary duties and other claims generally allege, among other things, that we subjected OOGC to excessive rates for gathering and other services provided for under the Development Agreement and interfered with OOGC's right to audit the documents that supported those rates. OOGC seeks relief that may be material, including unspecified damages, attorneys' fees, costs and expenses, disgorgement and various declaratory judgments. We intend to vigorously defend these claims.

On July 24, 2018, Healthcare of Ontario Pension Plan (HOOPP) filed a demand for arbitration with the American Arbitration Association 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 either rescission or $215 million in monetary damages, and in either case, interest, attorney's fees, disgorgement and punitive damages. We intend to vigorously defend these claims.

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:

| | June 30, 2018 ($ in millions) |
|---|---|
| 2018 | $ 537 |
| 2019 | 1,047 |
| 2020 | 992 |
| 2021 | 900 |
| 2022 | 792 |
| 2023 – 2035 | 4,434 |
| Total | $ 8,702 |

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 June 30, 2018 and December 31, 2017 are detailed below:

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| | ($ in millions) | |
| Revenues and royalties due others | $488 | $ 612 |
| Accrued drilling and production costs | 261 | 216 |
| Joint interest prepayments received | 81 | 74 |
| Accrued compensation and benefits | 156 | 214 |
| Other accrued taxes | 104 | 43 |
| Other | 187 | 296 |
| Total other current liabilities | $1,277 | $ 1,455 |

Other long-term liabilities as of June 30, 2018 and December 31, 2017 are detailed below:

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| | ($ in millions) | |
| CHK Utica ORRI conveyance obligation[a] | $— | $ 156 |
| Unrecognized tax benefits | 81 | 101 |
| Other | 96 | 97 |
| Total other long-term liabilities | $177 | $ 354 |

---

(a) In the Current Quarter, we repurchased previously conveyed overriding royalty interests (ORRI) from the CHK Utica, L.L.C. investors and extinguished our obligation to convey future ORRIs to the CHK Utica, L.L.C. investors for combined consideration of $199 million. The total CHK Utica ORRI conveyance obligation extinguished in the Current Quarter was $183 million, of which, $30 million was recorded in current liabilities and $153 million was recorded in long-term liabilities. The fair value of the consideration allocated to the extinguishment of liability, $122 million, was less than the carrying amount of the conveyance obligation and resulted in a gain of $61 million recognized in other income on our condensed consolidated statement of operations. The fair value of the consideration allocated to the purchase of ORRIs on proved producing properties was $77 million and recorded in proved oil and natural gas properties in our condensed consolidated balance sheet.

## 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 estimated annual effective tax rate as such items are recognized as discrete items in the quarter in which they occur.

For the Current Quarter, our estimated annual effective tax rate remains nominal as a result of having a full valuation allowance against 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 objectively verifiable negative evidence evaluated is the cumulative loss incurred over the rolling three-year period ending June 30, 2018. Such evidence limits our ability to consider various forms of 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 December 31, 2017 and against all of our net deferred tax asset as of June 30, 2018.

We are subject to U.S. federal income tax as well as income and capital taxes in various state jurisdictions in which we operate. We recorded a $9 million income tax benefit in the Current Quarter and the Current Period. This benefit was a result of discrete items consisting of a $13 million reduction to the liability for state unrecognized tax benefits due to the expiration of applicable statutes of limitations which was partially offset by eliminating a deferred tax asset for alternative minimum tax carryforwards in the amount of $3 million and recording additional state income tax expense of $1 million relating primarily to amended state income tax returns. A further reduction to the liability for state unrecognized tax benefits was also recorded against interest expense in the amount of $4 million.

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 six months ended June 30, 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 Period is presented below:

| | Shares of Unvested Restricted Stock (in thousands) | Weighted Average Grant Date Fair Value |
|---|---|---|
| Unvested restricted stock as of January 1, 2018 | 13,178 | $ 6.37 |
| Granted | 4,765 | $ 3.57 |
| Vested | (5,207) | $ 7.73 |

| | | |
|---|---|---|
| Forfeited | (1,295 ) | $ 6.13 |
| Unvested restricted stock as of June 30, 2018 | 11,441 | $ 4.61 |

The aggregate intrinsic value of restricted stock that vested during the Current Period was approximately $17 million based on the stock price at the time of vesting.

As of June 30, 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 2.20 years.

Stock Options. In the Current Period and the Prior Period, we granted members of management stock options that vest ratably over a three-year period. Each stock option award has an exercise price equal to the closing price of 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 Period:

| | | |
|---|---|---|
| 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 Period:

| | Number of Shares Underlying Options | Weighted Average Exercise Price Per Share | Weighted Average Contract Life in Years | Aggregate Intrinsic Value[(a)] |
|---|---|---|---|---|
| | (in thousands) | | | ($ in millions) |
| Outstanding as of January 1, 2018 | 16,285 | $ 8.25 | 7.73 | $ 1 |
| Granted | 3,611 | $ 3.01 | | |
| Exercised | — | $ — | | $ — |
| Expired | (602) | $ 13.83 | | |
| Forfeited | (995) | $ 5.45 | | |
| Outstanding as of June 30, 2018 | 18,299 | $ 7.18 | 7.71 | $ 14 |
| Exercisable as of June 30, 2018 | 8,250 | $ 10.73 | 6.34 | $ 3 |

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

As of June 30, 2018, there was $20 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 1.94 years.

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

| | Three Months Ended June 30, 2018 | 2017 | Six Months Ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| | ($ in millions) | | | |
| General and administrative expenses | $ 8 | $ 12 | $ 15 | $ 20 |

| | | | | |
|---|---|---|---|---|
| Oil and natural gas properties | 2 | 3 | 4 | 7 |
| Oil, natural gas and NGL production expenses | 1 | 4 | 3 | 7 |
| Total restricted stock and stock option compensation | $11 | $ 19 | $22 | $ 34 |

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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 2017 and 2016 PSU awards.

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 | 51.31 % | 59.84 % |
| Risk-free interest rate | 2.43 % | 2.11 % |
| 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. In the Current Period, 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.

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

| | Units | Grant Date Fair Value | June 30, 2018 Fair Value | June 30, 2018 Vested Liability |
|---|---|---|---|---|
| | | ($ in millions) | ($ in millions) | |
| 2018 PSU Awards: | | | | |
| Payable 2019, 2020 and 2021 | 3,992,358 | $ 12 | $ 21 | $ — |
| 2017 PSU Awards: | | | | |
| Payable 2020 | 1,217,774 | $ 8 | $ 8 | $ 5 |
| 2016 PSU Awards: | | | | |
| Payable 2019 | 2,348,893 | $ 10 | $ 16 | $ 14 |
| 2018 CRSU Awards: | | | | |
| Payable 2019, 2020 and 2021 | 16,367,724 | $ 49 | $ 86 | $ — |

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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 open oil, natural gas and NGL derivative instruments were designated for hedge accounting as of June 30, 2018 or December 31, 2017.

Oil, Natural Gas and NGL Derivatives

As of June 30, 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 June 30, 2018 and December 31, 2017 are provided below:

| | June 30, 2018 | | December 31, 2017 | |
|---|---|---|---|---|
| | Notional Volume | Fair Value | Notional Volume | Fair Value |
| | | ($ in millions) | | ($ in millions) |
| Oil (mmbbl): | | | | |
| Fixed-price swaps | 26 | $ (271) | 21 | $ (151) |
| Three-way collars | 1 | (14) | 2 | (10) |
| Call swaptions | 2 | (32) | 2 | (13) |
| Basis protection swaps | 11 | 6 | 11 | (9) |
| Total oil | 40 | (311) | 36 | (183) |
| Natural gas (bcf): | | | | |
| Fixed-price swaps | 240 | 3 | 532 | 149 |
| Three-way collars | 87 | — | — | — |
| Collars | 24 | 2 | 47 | 11 |
| Call options | 77 | — | 110 | (3) |
| Basis protection swaps | 45 | (1) | 65 | (7) |
| Total natural gas | 473 | 4 | 754 | 150 |
| NGL (mmgal): | | | | |
| Fixed-price swaps | 114 | (11) | 33 | (2) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total estimated fair value | $ | (318 | ) | $ | (35 | ) |

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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 June 30, 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 June 30, 2018 | | | |
| Commodity Contracts: | | | |
| Short-term derivative asset | $20 | $ (20) | $ — |
| Long-term derivative asset | 7 | (7) | — |
| Short-term derivative liability | (317) | 20 | (297) |
| Long-term derivative liability | (28) | 7 | (21) |
| Total derivatives | $(318) | $ — | $ (318) |
| 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) |

Effect of Derivative Instruments – Condensed Consolidated Statements of Operations

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | ($ in millions) | | | |
| Oil, natural gas and NGL revenues | $1,233 | $1,079 | $2,593 | $2,226 |
| Gains (losses) on undesignated oil, natural gas and NGL derivatives | (244) | 207 | (351) | 539 |
| Losses on terminated cash flow hedges | (7) | (7) | (17) | (17) |
| Total oil, natural gas and NGL revenues | $982 | $1,279 | $2,225 | $2,748 |

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 June 30, | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| | Before Tax | After Tax | Before Tax | After Tax |
| | ($ in millions) | | | |
| Balance, beginning of period | $(104) | $(47) | $(139) | (82) |
| Losses reclassified to income | 7 | 7 | 7 | 7 |
| Balance, end of period | $(97) | $(40) | (132) | (75) |

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | 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 | 17 | 17 | 17 | 17 |
| Balance, end of period | $(97) | $(40) | $(132) | $(75) |

The accumulated other comprehensive loss as of June 30, 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 June 30, 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 June 30, 2018, our oil, natural gas and NGL derivative instruments were spread among 11 counterparties.

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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. 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. As of June 30, 2018 and December 31, 2017, we did not have any cash collateral balances for our derivatives.

Fair Value

The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil, 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 June 30, 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 June 30, 2018 | | | | |
| Derivative Assets (Liabilities): | | | | |
| Commodity assets | $ — | $ 20 | $ 7 | $ 27 |
| Commodity liabilities | — | (293 ) | (52 ) | (345 ) |
| Total derivatives | $ — | $ (273 ) | $ (45 ) | $ (318 ) |
| As of December 31, 2017 | | | | |
| Derivative Assets (Liabilities): | | | | |
| Commodity assets | $ — | $ — | $ 8 | $ 8 |
| Commodity liabilities | — | (20 ) | (23 ) | (43 ) |
| Total derivatives | $ — | $ (20 ) | $ (15 ) | $ (35 ) |

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

| | Commodity Derivatives ($ in millions) |
|---|---|
| Balance, as of January 1, 2018 | $ (15 ) |
| Total gains (losses) (realized/unrealized): | |
| Included in earnings[(a)] | (32 ) |
| Total purchases, issuances, sales and settlements: | |
| Settlements | 2 |
| Balance, as of June 30, 2018 | $ (45 ) |
| | |
| Balance, as of January 1, 2017 | $ (10 ) |
| Total gains (losses) (realized/unrealized): | |
| Included in earnings[(a)] | 19 |
| Total purchases, issuances, sales and settlements: | |
| Settlements | 1 |
| Balance, as of June 30, 2017 | $ 10 |

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(a)

| | Commodity Derivatives 2018 | 2017 |
|---|---|---|
| | ($ in millions) | |
| Total gains (losses) included in earnings for the period | $ (32 ) | $ 19 |
| Change in unrealized gains (losses) related to assets still held at reporting date | $ (30 ) | $ 12 |

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

The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of natural gas, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts, which is based on an estimate derived from option models. For example, an increase or decrease in the forward prices and volatility of oil and natural gas prices decreases or increases the fair value of oil and natural gas derivatives, and adverse changes to our counterparties' creditworthiness decreases the fair value of our derivatives.

The following table presents quantitative information about Level 3 inputs used in the fair value measurement of our commodity derivative contracts at fair value as of June 30, 2018:

| Instrument Type | Unobservable Input | Range | Weighted Average | Fair Value June 30, 2018 ($ in millions) |
|---|---|---|---|---|
| Oil trades | Oil price volatility curves | 17.16% – 30.26% | 25.01% | $ (47 ) |
| Natural gas trades | Natural gas price volatility curves | 14.23% – 46.86% | 18.30% | $ 2 |

9. Oil and Natural Gas Property Transactions

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

In the Current Period, we sold portions of our acreage, producing properties and other related property and equipment in the Mid-Continent, including our Mississippian Lime assets, for approximately $491 million, subject to certain customary closing adjustments. Included in the sales were approximately 238,500 net acres and interests in approximately 3,200 wells. Also, in the Current Quarter and the Current Period, we received proceeds of approximately $5 million and $23 million, respectively, subject to customary closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

In the Prior Period, we sold portions of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $915 million, subject to certain customary closing adjustments. Included in the sales were approximately 119,500 net acres and interests in 576 wells that were producing approximately 80 mmcf of gas per day at the time of closing. Also in the Prior Quarter and the Prior Period, we received proceeds of approximately $63 million and $83 million, respectively, 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 June 30, 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 |

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The volumes remaining to be delivered on behalf of our VPP buyers as of June 30, 2018 were as follows:

| | | Volume Remaining as of June 30, 2018 | | | |
|---|---|---|---|---|---|
| VPP # | Term Remaining | Oil | Natural Gas | NGL | Total |
| | (in months) | (mmbbl) | (bcf) | (mmbbl) | (bcfe) |
| 9 | 32 | 0.3 | 28.5 | 0.8 | 34.8 |

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.

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 June 30, 2018 | | | |
| Other current liabilities | $1,275 | $ 2 | $1,277 |
| Other long-term liabilities | $172 | $ 5 | $177 |
| Accumulated deficit | $(16,249) | $ (8) | $(16,257) |
| | | | |
| Statement of Operations for the Three Months Ended June 30, 2018 | | | |
| Marketing revenues | $1,449 | $ (176) | $1,273 |
| Marketing operating expenses | $1,469 | $ (177) | $1,292 |
| | | | |
| Statement of Operations for the Six Months Ended June 30, 2018 | | | |
| Marketing revenues | $2,810 | $ (291) | $2,519 |
| Marketing operating expenses | $2,852 | $ (292) | $2,560 |

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.

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

| | Three Months Ended June 30, 2018 | | | |
|---|---|---|---|---|
| | Oil | Natural Gas | NGL | Total |
| | ($ in millions) | | | |
| Marcellus | $— | $169 | $— | $169 |
| Haynesville | 1 | 199 | — | 200 |
| Eagle Ford | 389 | 42 | 46 | 477 |
| Utica | 62 | 103 | 61 | 226 |
| Mid-Continent | 62 | 15 | 12 | 89 |
| Powder River Basin | 52 | 11 | 9 | 72 |
| Revenue from contracts with customers | 566 | 539 | 128 | 1,233 |
| Losses on oil, natural gas and NGL derivatives | (202) | (35) | (14) | (251) |
| Oil, natural gas and NGL revenue | $364 | $504 | $114 | $982 |
| | | | | |
| Marketing revenue from contracts with customers | $732 | $235 | $102 | $1,069 |
| Other marketing revenue | 145 | 59 | — | 204 |
| Marketing revenue | $877 | $294 | $102 | $1,273 |

| | Six Months Ended June 30, 2018 | | | |
|---|---|---|---|---|
| | Oil | Natural Gas | NGL | Total |
| | ($ in millions) | | | |
| Marcellus | $— | $463 | $— | $463 |
| Haynesville | 2 | 409 | — | 411 |
| Eagle Ford | 749 | 84 | 85 | 918 |
| Utica | 119 | 219 | 113 | 451 |
| Mid-Continent | 138 | 47 | 30 | 215 |
| Powder River Basin | 95 | 23 | 17 | 135 |
| Revenue from contracts with customers | 1,103 | 1,245 | 245 | 2,593 |
| Losses on oil, natural gas and NGL derivatives | (288) | (67) | (13) | (368) |
| Oil, natural gas and NGL revenue | $815 | $1,178 | $232 | $2,225 |
| | | | | |
| Marketing revenue from contracts with customers | $1,418 | $528 | $212 | $2,158 |
| Other marketing revenue | 262 | 99 | — | 361 |
| Marketing revenue | $1,680 | $627 | $212 | $2,519 |

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 June 30, 2018 and December 31, 2017 are detailed below:

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| | ($ in millions) | |
| Oil, natural gas and NGL sales | $801 | $ 959 |
| Joint interest | 206 | 209 |
| Other | 68 | 184 |
| Allowance for doubtful accounts | (15) | (30) |
| Total accounts receivable, net | $1,060 | $ 1,322 |

11. Investments

In the Current Period, 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. Impairments

In the Current Quarter, we have determined that certain of our other fixed assets will either be sold or disposed before the end of their useful lives indicating the carrying value may not be recoverable. As a result, we recognized an impairment loss of $42 million in the Current Quarter for the difference between the carrying amount and fair value of the assets.

13. Other Operating Expenses

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

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(Unaudited)

## 14. 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 Period 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 | (38) |
| Balance as of June 30, 2018 | $ — |

## 15. 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 June 30, 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 June 30, 2018 | | | | |
| Financial Assets (Liabilities): | | | | |
| Other current assets | $ 53 | $ — | $ — | $ 53 |
| Other current liabilities | (52) | — | — | (52) |
| Total | $ 1 | $ — | $ — | $ 1 |
| | | | | |
| 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.

16. 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 June 30, 2018 and December 31, 2017 and for the three and six months ended June 30, 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.

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

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF JUNE 30, 2018
($ in millions)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| CURRENT ASSETS: | | | | | |
| Cash and cash equivalents | $5 | $ 1 | $ 2 | $ (5 ) | $ 3 |
| Other current assets | 63 | 1,173 | 1 | — | 1,237 |
| Intercompany receivable, net | 8,132 | 31 | 175 | (8,338 ) | — |
| Total Current Assets | 8,200 | 1,205 | 178 | (8,343 ) | 1,240 |
| PROPERTY AND EQUIPMENT: | | | | | |
| Oil and natural gas properties at cost, based on full cost accounting, net | 521 | 9,129 | 25 | — | 9,675 |
| Other property and equipment, net | — | 1,164 | — | — | 1,164 |
| Property and equipment held for sale, net | — | 11 | — | — | 11 |
| Total Property and Equipment, Net | 521 | 10,304 | 25 | — | 10,850 |
| LONG-TERM ASSETS: | | | | | |
| Other long-term assets | 44 | 207 | — | — | 251 |
| Investments in subsidiaries and intercompany advances | 907 | 78 | — | (985 ) | — |
| TOTAL ASSETS | $9,672 | $ 11,794 | $ 203 | $ (9,328 ) | $ 12,341 |
| | | | | | |
| CURRENT LIABILITIES: | | | | | |
| Current liabilities | $561 | $ 2,315 | $ 2 | $ (5 ) | $ 2,873 |
| Intercompany payable, net | 32 | 8,306 | — | (8,338 ) | — |
| Total Current Liabilities | 593 | 10,621 | 2 | (8,343 ) | 2,873 |
| LONG-TERM LIABILITIES: | | | | | |
| Long-term debt, net | 9,238 | — | — | — | 9,238 |
| Other long-term liabilities | 81 | 266 | — | — | 347 |
| Total Long-Term Liabilities | 9,319 | 266 | — | — | 9,585 |
| EQUITY: | | | | | |
| Chesapeake stockholders’ equity (deficit) | (240 ) | 907 | 78 | (985 ) | (240 ) |
| Noncontrolling interests | — | — | 123 | — | 123 |
| Total Equity (Deficit) | (240 ) | 907 | 201 | (985 ) | (117 ) |
| TOTAL LIABILITIES AND EQUITY | $9,672 | $ 11,794 | $ 203 | $ (9,328 ) | $ 12,341 |

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

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 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 |

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

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED JUNE 30, 2018
($ in millions)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| REVENUES: | | | | | |
| Oil, natural gas and NGL | $ — | $ 978 | $ 4 | $ — | $ 982 |
| Marketing | — | 1,273 | — | — | 1,273 |
| Total Revenues | — | 2,251 | 4 | — | 2,255 |
| OPERATING EXPENSES: | | | | | |
| Oil, natural gas and NGL production | — | 138 | — | — | 138 |
| Oil, natural gas and NGL gathering, processing and transportation | — | 338 | 2 | — | 340 |
| Production taxes | — | 26 | — | — | 26 |
| Marketing | — | 1,292 | — | — | 1,292 |
| General and administrative | — | 90 | 1 | — | 91 |
| Provision for legal contingencies, net | — | 4 | — | — | 4 |
| Oil, natural gas and NGL depreciation, depletion and amortization | — | 270 | 1 | — | 271 |
| Depreciation and amortization of other assets | — | 19 | — | — | 19 |
| Impairments | — | 46 | — | — | 46 |
| Other operating income | — | (1) | — | — | (1) |
| Net gains on sales of fixed assets | — | (1) | — | — | (1) |
| Total Operating Expenses | — | 2,221 | 4 | — | 2,225 |
| INCOME FROM OPERATIONS | — | 30 | — | — | 30 |
| OTHER INCOME (EXPENSE): | | | | | |
| Interest expense | (117) | — | — | — | (117) |
| Other income | — | 62 | — | — | 62 |
| Equity in net earnings (losses) of subsidiary | 91 | (1) | — | (90) | — |
| Total Other Income (Expense) | (26) | 61 | — | (90) | (55) |
| INCOME (LOSS) BEFORE INCOME TAXES | (26) | 91 | — | (90) | (25) |
| INCOME TAX BENEFIT | (9) | — | — | — | (9) |
| NET INCOME (LOSS) | (17) | 91 | — | (90) | (16) |
| Net income attributable to noncontrolling interests | — | — | (1) | — | (1) |
| NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE | (17) | 91 | (1) | (90) | (17) |
| Other comprehensive income | — | 7 | — | — | 7 |
| COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE | $ (17) | $ 98 | $ (1) | $ (90) | $ (10) |

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(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED JUNE 30, 2017
($ in millions)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| REVENUES: | | | | | |
| Oil, natural gas and NGL | $ — | $ 1,273 | $ 6 | $ — | $ 1,279 |
| Marketing | — | 1,002 | — | — | 1,002 |
| Total Revenues | — | 2,275 | 6 | — | 2,281 |
| OPERATING EXPENSES: | | | | | |
| Oil, natural gas and NGL production | — | 140 | — | — | 140 |
| Oil, natural gas and NGL gathering, processing and transportation | — | 355 | 2 | — | 357 |
| Production taxes | — | 21 | — | — | 21 |
| Marketing | — | 1,027 | — | — | 1,027 |
| General and administrative | 3 | 67 | — | — | 70 |
| Provision for legal contingencies, net | — | 17 | — | — | 17 |
| Oil, natural gas and NGL depreciation, depletion and amortization | — | 202 | — | — | 202 |
| Depreciation and amortization of other assets | — | 21 | — | — | 21 |
| Net losses on sales of fixed assets | — | 1 | — | — | 1 |
| Other operating expense | — | 26 | — | — | 26 |
| Total Operating Expenses | 3 | 1,877 | 2 | — | 1,882 |
| INCOME (LOSS) FROM OPERATIONS | (3) | 398 | 4 | — | 399 |
| OTHER INCOME (EXPENSE): | | | | | |
| Interest income (expense) | (95) | 2 | — | — | (93) |
| Gains on purchases or exchanges of debt | 191 | — | — | — | 191 |
| Other expense | — | (1) | — | — | (1) |
| Equity in net earnings of subsidiary | 402 | 3 | — | (405) | — |
| Total Other Income | 498 | 4 | — | (405) | 97 |
| INCOME BEFORE INCOME TAXES | 495 | 402 | 4 | (405) | 496 |
| INCOME TAX EXPENSE | 1 | — | — | — | 1 |
| NET INCOME | 494 | 402 | 4 | (405) | 495 |
| Net income attributable to noncontrolling interests | — | — | (1) | — | (1) |
| NET INCOME ATTRIBUTABLE TO CHESAPEAKE | 494 | 402 | 3 | (405) | 494 |
| Other comprehensive income | — | 7 | — | — | 7 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE | $ 494 | $ 409 | $ 3 | $ (405) | $ 501 |

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(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2018
($ in millions)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| REVENUES: | | | | | |
| Oil, natural gas and NGL | $ — | $ 2,216 | $ 9 | $ — | $ 2,225 |
| Marketing | — | 2,519 | — | — | 2,519 |
| Total Revenues | — | 4,735 | 9 | — | 4,744 |
| OPERATING EXPENSES: | | | | | |
| Oil, natural gas and NGL production | — | 285 | — | — | 285 |
| Oil, natural gas and NGL gathering, processing and transportation | — | 693 | 3 | — | 696 |
| Production taxes | — | 57 | — | — | 57 |
| Marketing | — | 2,560 | — | — | 2,560 |
| General and administrative | — | 162 | 1 | — | 163 |
| Restructuring and other termination costs | — | 38 | — | — | 38 |
| Provision for legal contingencies, net | — | 9 | — | — | 9 |
| Oil, natural gas and NGL depreciation, depletion and amortization | — | 537 | 2 | — | 539 |
| Depreciation and amortization of other assets | — | 37 | — | — | 37 |
| Impairments | — | 46 | — | — | 46 |
| Other operating income | — | (1 ) | — | — | (1 ) |
| Net losses on sales of fixed assets | — | 7 | — | — | 7 |
| Total Operating Expenses | — | 4,430 | 6 | — | 4,436 |
| INCOME FROM OPERATIONS | — | 305 | 3 | — | 308 |
| OTHER INCOME (EXPENSE): | | | | | |
| Interest expense | (240 ) | — | — | — | (240 ) |
| Gains on investments | — | 139 | — | — | 139 |
| Other income | — | 62 | — | — | 62 |
| Equity in net earnings (losses) of subsidiary | 507 | 1 | — | (508 ) | — |
| Total Other Income (Expense) | 267 | 202 | — | (508 ) | (39 ) |
| INCOME BEFORE INCOME TAXES | 267 | 507 | 3 | (508 ) | 269 |
| INCOME TAX BENEFIT | (9 ) | — | — | — | (9 ) |
| NET INCOME | 276 | 507 | 3 | (508 ) | 278 |
| Net income attributable to noncontrolling interests | — | — | (2 ) | — | (2 ) |
| NET INCOME ATTRIBUTABLE TO CHESAPEAKE | 276 | 507 | 1 | (508 ) | 276 |
| Other comprehensive income | — | 17 | — | — | 17 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE | $ 276 | $ 524 | $ 1 | $ (508 ) | $ 293 |

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

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2017
($ in millions)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| REVENUES: | | | | | |
| Oil, natural gas and NGL | $ — | $ 2,736 | $ 12 | $ — | $ 2,748 |
| Marketing | — | 2,286 | — | — | 2,286 |
| Total Revenues | — | 5,022 | 12 | — | 5,034 |
| OPERATING EXPENSES: | | | | | |
| Oil, natural gas and NGL production | — | 275 | — | — | 275 |
| Oil, natural gas and NGL gathering, processing and transportation | — | 708 | 4 | — | 712 |
| Production taxes | — | 43 | — | — | 43 |
| Marketing | — | 2,355 | — | — | 2,355 |
| General and administrative | 3 | 131 | 1 | — | 135 |
| Provision for legal contingencies, net | — | 15 | — | — | 15 |
| Oil, natural gas and NGL depreciation, depletion and amortization | — | 397 | 2 | — | 399 |
| Depreciation and amortization of other assets | — | 42 | — | — | 42 |
| Other operating expense | — | 417 | — | — | 417 |
| Net losses on sales of fixed assets | — | 1 | — | — | 1 |
| Total Operating Expenses | 3 | 4,384 | 7 | — | 4,394 |
| INCOME (LOSS) FROM OPERATIONS | (3) | 638 | 5 | — | 640 |
| OTHER INCOME (EXPENSE): | | | | | |
| Interest expense | (190) | 2 | — | — | (188) |
| Gains on purchases or exchanges of debt | 184 | — | — | — | 184 |
| Other income | — | 2 | — | — | 2 |
| Equity in net earnings of subsidiary | 645 | 3 | — | (648) | — |
| Total Other Income (Expense) | 639 | 7 | — | (648) | (2) |
| INCOME BEFORE INCOME TAXES | 636 | 645 | 5 | (648) | 638 |
| INCOME TAX EXPENSE | 2 | — | — | — | 2 |
| NET INCOME | 634 | 645 | 5 | (648) | 636 |
| Net income attributable to noncontrolling interests | — | — | (2) | — | (2) |
| NET INCOME ATTRIBUTABLE TO CHESAPEAKE | 634 | 645 | 3 | (648) | 634 |
| Other comprehensive income | — | 21 | — | — | 21 |
| COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE | $ 634 | $ 666 | $ 3 | $ (648) | $ 655 |

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

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
SIX MONTHS ENDED JUNE 30, 2018
($ in millions)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | | | |
| Net Cash Provided By Operating Activities | $ 88 | $ 1,006 | $ 5 | $ (8) | $ 1,091 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | | | |
| Drilling and completion costs | — | (979) | — | — | (979) |
| Acquisitions of proved and unproved properties | — | (191) | — | — | (191) |
| Proceeds from divestitures of proved and unproved properties | — | 384 | — | — | 384 |
| Additions to other property and equipment | — | (5) | — | — | (5) |
| Other investing activities | — | 148 | — | — | 148 |
| Net Cash Used In Investing Activities | — | (643) | — | — | (643) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | | | |
| Proceeds from revolving credit facility borrowings | 6,118 | — | — | — | 6,118 |
| Payments on revolving credit facility borrowings | (6,393) | — | — | — | (6,393) |
| Cash paid for preferred stock dividends | (46) | — | — | — | (46) |
| Other financing activities | (2) | (126) | (7) | 6 | (129) |
| Intercompany advances, net | 235 | (237) | 2 | — | — |
| Net Cash Used In Financing Activities | (88) | (363) | (5) | 6 | (450) |
| Net decrease in cash and cash equivalents | — | — | — | (2) | (2) |
| Cash and cash equivalents, beginning of period | 5 | 1 | 2 | (3) | 5 |
| Cash and cash equivalents, end of period | $ 5 | $ 1 | $ 2 | $ (5) | $ 3 |

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

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
SIX MONTHS ENDED JUNE 30, 2017
($ in millions)

| | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Consolidated |
|---|---|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | | | |
| Net Cash Provided By (Used In) Operating Activities | $ 2 | $ (64) | $ 8 | $ (4) | $ (58) |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | | | |
| Drilling and completion costs | — | (1,031) | — | — | (1,031) |
| Acquisitions of proved and unproved properties | — | (162) | — | — | (162) |
| Proceeds from divestitures of proved and unproved properties | — | 951 | — | — | 951 |
| Additions to other property and equipment | — | (7) | — | — | (7) |
| Other investing activities | — | 26 | — | — | 26 |
| Net Cash Used In Investing Activities | — | (223) | — | — | (223) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | | | |
| Proceeds from revolving credit facility borrowings | 2,551 | — | — | — | 2,551 |
| Payments on revolving credit facility borrowings | (1,976) | — | — | — | (1,976) |
| Proceeds from issuance of senior notes, net | 742 | — | — | — | 742 |
| Cash paid to purchase debt | (1,746) | — | — | — | (1,746) |
| Cash paid for preferred stock dividends | (137) | — | — | — | (137) |
| Other financing activities | (38) | (2) | (7) | 25 | (22) |
| Intercompany advances, net | (287) | 288 | (1) | — | — |
| Net Cash Provided by (Used In) Financing Activities | (891) | 286 | (8) | 25 | (588) |
| Net increase (decrease) in cash and cash equivalents | (889) | (1) | — | 21 | (869) |
| Cash and cash equivalents, beginning of period | 904 | 2 | 1 | (25) | 882 |
| Cash and cash equivalents, end of period | $ 15 | $ 1 | $ 1 | $ (4) | $ 13 |

17. Subsequent Events

On July 26, 2018 we entered into a purchase and sale agreement (the "Purchase Agreement") with EAP Ohio, LLC, a private oil and gas company headquartered in Houston, Texas ("Encino"), pursuant to which Encino agreed to purchase all of our approximately 1,500,000 gross (900,000 net) acres in Ohio, of which approximately 320,000 net acres are prospective for the Utica Shale with approximately 920 producing wells, along with related property and equipment (collectively, the "Designated Properties") for a purchase price of approximately \$2.0 billion, with additional contingent payments to us of up to \$100 million comprised of \$50 million in consideration in each case if, on or prior to December 31, 2019, there is a period of twenty (20) trading days out of a period of thirty (30) consecutive trading days where (i) the average of the NYMEX natural gas strip pries for the months comprising the year 2022 equals or exceeds \$3.00/mmbtu as calculated pursuant to the agreement, and (ii) the average of the NYMEX natural gas price strip prices for the months comprising the year 2023 equals or exceeds \$3.25/mmbtu as calculated pursuant to the agreement.

Average net daily production from the Designated Properties was approximately 107,000 boe during 2017 consisting of 427,000 mcf of natural gas, 26,000 barrels of natural gas liquids and 10,000 barrels of oil. As of December 31, 2017, net proved reserves associated with the Designated Properties were 480 million boe (72% natural gas, 23% natural gas liquids and 5% oil).

Closing of the transaction is subject to customary conditions, including waiver of certain pre-existing preferential purchase rights, expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, other regulatory approvals and certain other closing conditions. Closing is expected to occur in the fourth quarter of 2018, contingent upon satisfaction of such closing conditions and the absence of termination rights. We expect to apply the net proceeds toward the reduction of debt.

Pursuant to the Purchase Agreement, the purchase price is subject to customary adjustment provisions, including for results of operations, adjustments for title and environmental defects and preferential purchase rights. The Purchase Agreement also contains customary representations, warranties, covenants and indemnities.

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## 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 14,700 oil and natural gas wells. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas, the stacked pay in the Powder River Basin in Wyoming and the Anadarko Basin in northwestern Oklahoma. Our natural gas resource plays are the Marcellus Shale in the northern Appalachian Basin in Pennsylvania and the Haynesville/Bossier Shales in northwestern Louisiana and East Texas.

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.

On July 26, 2018 we announced the execution of a definitive agreement to divest of all of our assets in Ohio, which target the Utica formation. This divestiture, upon closing, will result in our meeting or making significant progress toward all three of these priorities. The following discussion and analysis presents management’s perspective of our business and material changes to our results of operations for the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017 and in our financial condition and liquidity since December 31, 2017.

### Overview

The transformation of Chesapeake over the past five years has been significant and our progress has continued in the Current Period. 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 Period 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.

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We have made significant progress towards achieving our strategic priorities to date through August 1, 2018. So far we have:

- entered into an agreement to sell our interests in the Utica Shale operating area located in Ohio for approximately $2.0 billion, with an additional contingent payment to us of up to $100 million based on future natural gas prices;
- repurchased the CHK Utica, L.L.C. investors’ ORRI for $199 million in an effort to remove financial and operational complexity and to improve our balance sheet;
- 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.

We continue to benefit from progress made over the last five years, including removing financial and operational complexity, significantly improving our balance sheet and addressing numerous legacy issues.

Financial Results

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change[b] | 2018 | 2017 | Change[b] |
| | ($ in millions) | | | | | |
| Net income (loss) available to common stockholders | $(40 ) | $470 | n/m | $228 | $547 | (58 )% |
| Net earnings (loss) per diluted common share | $(0.04 ) | $0.47 | n/m | $0.25 | $0.59 | (58 )% |
| Adjusted production[a] (mboe per day) | 531 | 493 | 8 % | 533 | 486 | 10 % |
| Total production (mboe per day) | 530 | 528 | — % | 542 | 528 | 3 % |
| Average sales price (per boe) | $25.56 | $22.46 | 14 % | $26.43 | $23.29 | 13 % |
| Oil, natural gas and NGL production expenses | $138 | $140 | (1 )% | $285 | $275 | 4 % |
| Oil, natural gas and NGL gathering, processing and transportation expenses | $340 | $357 | (5 )% | $696 | $712 | (2 )% |
| General and administrative expenses | $91 | $70 | 30 % | $163 | $135 | 21 % |

| | June 30, 2018 | December 31, 2017 | Change |
|---|---|---|---|
| Total debt (principal amount) | $9,706 | $9,981 | (3 )% |

(a) Adjusted for assets sold.
(b) n/m - not meaningful.

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## Liquidity and Capital Resources

### Liquidity Overview

Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and NGL we sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been very volatile, and may be subject to wide fluctuations in the future. The substantial decline in oil, natural gas and NGL prices from 2014 levels has negatively affected the amount of cash we generate and have available for capital expenditures and debt service 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 June 30, 2018, we had a cash balance of $3 million compared to $5 million as of December 31, 2017, and we had a net working capital deficit of $1.633 billion as of June 30, 2018, compared to a net working capital deficit of $831 million as of December 31, 2017. As of June 30, 2018, our working capital deficit includes $433 million principal amount of debt due or that could be put to us in the next 12 months. As of June 30, 2018, we had $3.096 billion of borrowing capacity available under our senior secured revolving credit facility, with outstanding borrowings of $506 million and $183 million utilized for various letters of credit. Based on our cash balance, forecasted cash flows from operating activities, availability under our revolving credit facility and expected net proceeds from the pending sale of our Utica interests, 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 elsewhere in our periodic reports and the other risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

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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 July 24, 2018, we have downside price protection in the second half of 2018 and 2019 through the following oil, natural gas and NGL derivative instruments:

Oil Derivatives[(a)]

| Year | Type of Derivative Instrument | Notional Volume (mbbls) | % of Forecasted Production (if applicable) | Average NYMEX Price |
|---|---|---|---|---|
| 2018 | Swaps | 13,064 | 84% | $54.09 |
| 2018 | Three-way collars | 920 | 6% | $39.15/$47.00/$55.00 |
| 2018 | Basis protection swaps | 7,176 | 48% | $3.54 |
| 2019 | Swaps | 14,763 | Not disclosed | $59.44 |
| 2019 | Basis protection swaps | 4,015 | Not disclosed | $6.20 |

Natural Gas Derivatives[(a)]

| Year | Type of Derivative Instrument | Notional Volume (bcf) | % of Forecasted Production (if applicable) | Average NYMEX Price |
|---|---|---|---|---|
| 2018 | Swaps | 240 | 63% | $2.97 |
| 2018 | Collars | 24 | 6% | $3.00/$3.25 |
| 2018 | Calls | 33 | 9% | $6.27 |
| 2018 | Basis protection swaps | 23 | 6% | ($0.77) |
| 2019 | Three-way collars | 88 | Not disclosed | $2.50/$2.80/$3.10 |
| 2019 | Basis protection swaps | 38 | Not disclosed | $0.03 |
| 2019 | Calls | 22 | Not disclosed | $12.00 |
| 2020 | Calls | 22 | Not disclosed | $12.00 |

NGL Derivatives[(a)]

| Year | Type of Derivative Instrument | Notional Volume (mmgal) | % of Forecasted Production (if applicable) | Average NYMEX Price |
|---|---|---|---|---|
| 2018 | Butane swaps | 3 | 7% | $0.88 |
| 2018 | Butane % of WTI swaps | 3 | 7% | 70.5% of WTI |
| 2018 | Propane swaps | 31 | 29% | $0.79 |
| 2018 | Ethane swaps | 46 | 36% | $0.29 |
| 2018 | Isobutane swaps | 8 | 33% | $0.92 |
| 2018 | Natural gasoline | 23 | 63% | $1.42 |

(a) Includes amounts settled in July 2018.

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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 June 30, 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 in 2018. To accomplish this objective, we intend to use the anticipated net proceeds from the pending sale of our Utica interests, 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 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 and the proceeds from asset sales 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 fourth quarter of 2018. Our borrowing base could be reduced at the first borrowing base redetermination after the closing date of our pending sale of our Utica interests. As of June 30, 2018, we had $3.096 billion of borrowing capacity available under our revolving credit facility. As of June 30, 2018, we had outstanding borrowings of $506 million under the revolving credit facility and had used $183 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 June 30, 2018, we were in compliance with all applicable financial covenants under the credit agreement. Our first lien secured leverage ratio was approximately 0.28 to 1.00, our interest coverage ratio was approximately 3.34 to 1.00 and our debt to capitalization ratio was approximately 0.38 to 1.00.

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Capital Expenditures

Our 2018 capital expenditures program, while planned to be approximately 7% 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 $2.2 – $2.5 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 July 27, 2018, we have received requests and posted approximately $203 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 $468 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 Period and the Prior Period. See Note 9 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of divestitures of oil and natural gas assets.

| | Six Months Ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| | ($ in millions) | |
| Cash provided by (used in) operating activities | $1,091 | $(58) |
| Proceeds from divestitures of proved and unproved properties, net | 384 | 951 |
| Proceeds from issuance of senior notes, net | — | 742 |
| Proceeds from issuance of credit facility borrowings, net | — | 575 |
| Proceeds from sales of other property and equipment, net | 74 | 26 |
| Proceeds from sales of investments | 74 | — |
| Total sources of cash and cash equivalents | $1,623 | $2,236 |

Cash Flow from Operating Activities

Cash provided by operating activities was $1.091 billion in the Current Period compared to cash used by operating activities of $58 million in the Prior Period. The increase in the Current Period is primarily due to the result of higher prices for the oil and NGL we sold and higher volumes of oil and natural gas sold. 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.

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Uses of Funds

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

| | Six Months Ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| | ($ in millions) | |
| Oil and Natural Gas Expenditures: | | |
| Drilling and completion costs | $979 | $1,031 |
| Acquisitions of proved and unproved properties | 110 | 69 |
| Interest capitalized on unproved leasehold | 81 | 93 |
| Total oil and natural gas expenditures | 1,170 | 1,193 |
| Other Uses of Cash and Cash Equivalents: | | |
| Payments on revolving credit facility borrowings, net | 275 | — |
| Extinguishment of other financings | 122 | — |
| Cash paid to repurchase debt | — | 1,746 |
| Additions to other property and equipment | 5 | 7 |
| Dividends paid | 46 | 137 |
| Other | 7 | 22 |
| Total other uses of cash and cash equivalents | 455 | 1,912 |
| Total uses of cash and cash equivalents | $1,625 | $3,105 |

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Oil and Natural Gas Expenditures

Our drilling and completion costs decreased in the Current Period compared to the Prior Period primarily as a result of lower rig and completion costs. During the Current Period, our average operated rig count was 16 rigs compared to an average operated rig count of 18 rigs in the Prior Period and we completed 161 operated wells in the Current Period compared to 206 in the Prior Period.

Extinguishment of Other Financing

In the Current Quarter, we repurchased previously conveyed overriding royalty interests (ORRIs) from the CHK Utica, L.L.C. investors and extinguished our obligation to convey future ORRIs to the investors for combined consideration of $199 million. The cash paid was bifurcated between extinguishment of the obligation and acquisition of the ORRI. See Note 5 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the transaction.

Repurchase of Debt

In the Prior Period, we used $1.746 billion of cash from debt issuances to repurchase $1.604 billion principal amount of debt.

Dividends

We paid dividends of $46 million on our preferred stock during the Current Period and we paid dividends of $137 million on our preferred stock in the Prior Period, 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.

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Results of Operations

Oil, Natural Gas and NGL Production and Average Sales Prices

| | Three Months Ended June 30, 2018 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil | | Natural Gas | | NGL | | Total | | |
| | mbbl per day | $/bbl | mmcf per day | $/mcf | mbbl per day | $/bbl | mboe per day | % | $/boe |
| Marcellus | — | — | 805 | 2.31 | — | — | 134 | 25 | 13.83 |
| Haynesville | — | — | 830 | 2.63 | — | — | 139 | 26 | 15.84 |
| Eagle Ford | 61 | 70.51 | 143 | 3.22 | 19 | 26.56 | 103 | 20 | 50.70 |
| Utica | 11 | 63.50 | 408 | 2.76 | 27 | 25.11 | 106 | 20 | 23.53 |
| Mid-Continent | 10 | 66.45 | 70 | 2.37 | 5 | 24.49 | 27 | 5 | 35.82 |
| Powder River Basin | 8 | 67.37 | 57 | 2.18 | 4 | 27.12 | 22 | 4 | 36.82 |
| Retained assets[(a)] | 90 | 68.91 | 2,313 | 2.56 | 55 | 25.68 | 531 | 100 | 25.54 |
| Divested assets | — | — | (2 ) | 2.51 | — | — | (1 ) | — | (8.48 ) |
| Total | 90 | 68.92 | 2,311 | 2.56 | 55 | 25.74 | 530 | 100% | 25.56 |

| | Three Months Ended June 30, 2017 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil | | Natural Gas | | NGL | | Total | | |
| | mbbl per day | $/bbl | mmcf per day | $/mcf | mbbl per day | $/bbl | mboe per day | % | $/boe |
| Marcellus | — | — | 805 | 2.56 | — | — | 134 | 25 | 15.33 |
| Haynesville | — | — | 722 | 2.97 | — | — | 121 | 23 | 17.86 |
| Eagle Ford | 58 | 48.28 | 149 | 3.44 | 18 | 19.40 | 100 | 19 | 36.27 |
| Utica | 8 | 42.47 | 373 | 3.21 | 26 | 16.96 | 97 | 18 | 20.62 |
| Mid-Continent | 8 | 46.39 | 71 | 3.01 | 5 | 18.48 | 25 | 5 | 27.19 |
| Powder River Basin | 7 | 47.91 | 38 | 2.99 | 3 | 21.74 | 16 | 3 | 31.31 |
| Retained assets[(a)] | 81 | 47.46 | 2,158 | 2.89 | 52 | 18.21 | 493 | 93 | 22.37 |
| Divested assets | 7 | 47.98 | 136 | 2.75 | 5 | 20.09 | 35 | 7 | 23.84 |
| Total | 88 | 47.51 | 2,294 | 2.88 | 57 | 18.37 | 528 | 100% | 22.46 |

| | Six Months Ended June 30, 2018 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil | | Natural Gas | | NGL | | Total | | |
| | mbbl per day | $/bbl | mmcf per day | $/mcf | mbbl per day | $/bbl | mboe per day | % | $/boe |
| Marcellus | — | — | 839 | 3.05 | — | — | 140 | 26 | 18.30 |
| Haynesville | — | — | 832 | 2.71 | — | — | 139 | 25 | 16.34 |
| Eagle Ford | 61 | 68.35 | 142 | 3.26 | 19 | 25.67 | 103 | 19 | 49.48 |
| Utica | 11 | 61.69 | 424 | 2.85 | 25 | 25.08 | 106 | 19 | 23.46 |
| Mid-Continent | 9 | 64.45 | 67 | 2.52 | 5 | 25.33 | 25 | 5 | 35.22 |
| Powder River Basin | 8 | 65.28 | 52 | 2.46 | 3 | 27.84 | 20 | 4 | 37.21 |
| Retained assets[(a)] | 89 | 66.84 | 2,356 | 2.88 | 52 | 25.48 | 533 | 98 | 26.34 |
| Divested assets | 2 | 63.69 | 32 | 2.80 | 1 | 29.93 | 9 | 2 | 31.29 |
| Total | 91 | 66.76 | 2,388 | 2.88 | 53 | 25.60 | 542 | 100% | 26.43 |

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| | Six Months Ended June 30, 2017 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil | | Natural Gas | | NGL | | Total | | |
| | mbbl per day | $/bbl | mmcf per day | $/mcf | mbbl per day | $/bbl | mboe per day | % | $/boe |
| Marcellus | — | — | 821 | 2.78 | — | — | 137 | 26 | 16.71 |
| Haynesville | — | — | 702 | 2.97 | — | — | 117 | 22 | 17.86 |
| Eagle Ford | 57 | 49.58 | 142 | 3.42 | 18 | 20.37 | 98 | 19 | 37.37 |
| Utica | 8 | 43.88 | 376 | 3.35 | 26 | 21.20 | 96 | 18 | 22.38 |
| Mid-Continent | 7 | 47.75 | 69 | 3.01 | 5 | 20.35 | 24 | 4 | 27.43 |
| Powder River Basin | 6 | 48.63 | 33 | 3.14 | 2 | 23.39 | 14 | 3 | 31.88 |
| Retained assets[(a)] | 78 | 48.75 | 2,143 | 3.00 | 51 | 20.93 | 486 | 92 | 23.24 |
| Divested assets | 8 | 49.52 | 175 | 2.85 | 4 | 21.67 | 42 | 8 | 23.89 |
| Total | 86 | 48.83 | 2,318 | 2.99 | 55 | 20.99 | 528 | 100% | 23.29 |

(a) Includes assets retained as of June 30, 2018.

Oil, Natural Gas and NGL Sales

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions) | | | | | |
| Oil | $567 | $383 | 48 % | $1,104 | $761 | 45 % |
| Natural gas | 538 | 601 | (10 )% | 1,244 | 1,254 | (1 )% |
| NGL | 128 | 95 | 35 % | 245 | 211 | 16 % |
| Oil, natural gas and NGL sales | $1,233 | $1,079 | 14 % | $2,593 | $2,226 | 16 % |

The increase in the price received per boe in the Current Quarter resulted in a $149 million increase in revenues, and increased sales volumes resulted in a $5 million increase in revenues, for a total net increase in revenues of $154 million. The increase in the price received per boe in the Current Period resulted in a $307 million increase in revenues, and increased sales volumes resulted in a $60 million increase in revenues, for a total net increase in revenues of $367 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 $21 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. Assuming our Current Period production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would have resulted in an increase or decrease in Current Period revenues and cash flows from operations of approximately $16 million, an increase or decrease of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in Current Period revenues and cash flows from operations of approximately $43 million and an increase or decrease of $1.00 per barrel of NGL sold would have resulted in an increase or decrease in Current Period revenues and cash flows from operations of approximately $10 million and $9 million, respectively.

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Oil, Natural Gas and NGL Derivatives

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | ($ in millions) | | | |
| Oil derivatives – realized gains (losses) | $(97) | $33 | $(161) | $44 |
| Oil derivatives – unrealized gains (losses) | (105) | 47 | (127) | 141 |
| Total gains (losses) on oil derivatives | (202) | 80 | (288) | 185 |
| | | | | |
| Natural gas derivatives – realized gains (losses) | 17 | (36) | 84 | (52) |
| Natural gas derivatives – unrealized gains (losses) | (52) | 156 | (151) | 387 |
| Total gains (losses) on natural gas derivatives | (35) | 120 | (67) | 335 |
| | | | | |
| NGL derivatives – realized gains (losses) | (3) | 1 | (4) | 2 |
| NGL derivatives – unrealized gains (losses) | (11) | (1) | (9) | — |
| Total gains (losses) on NGL derivatives | (14) | — | (13) | 2 |
| Total gains (losses) on oil, natural gas and NGL derivatives | $(251) | $200 | $(368) | $522 |

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

In connection with the marketing of our production, we take title to the oil, natural gas and NGL we purchase from other working interest owners at defined delivery points and deliver the product to third parties, at which time revenues are recorded. In circumstances where we act as a principal rather than an agent, revenue is presented on a gross basis. 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.

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions) | | | | | |
| Marketing revenues | 1,273 | 1,002 | 27 % | $2,519 | $2,286 | 10 % |
| Marketing expenses | 1,292 | 1,027 | 26 % | 2,560 | 2,355 | 9 % |
| Marketing gross margin | $(19) | $(25) | (24 )% | $(41) | $(69) | (41 )% |

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

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Oil, Natural Gas and NGL Production Expenses

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions) | | | | | |
| Marcellus | $7 | $5 | 40 % | $15 | $10 | 50 % |
| Haynesville | 14 | 12 | 17 % | 30 | 22 | 36 % |
| Eagle Ford | 52 | 49 | 6 % | 100 | 91 | 10 % |
| Utica | 11 | 10 | 10 % | 22 | 19 | 16 % |
| Mid-Continent | 23 | 27 | (15 )% | 49 | 53 | (8 )% |
| Powder River Basin | 11 | 6 | 83 % | 23 | 13 | 77 % |
| Retained Assets[(a)] | 118 | 109 | 8 % | 239 | 208 | 15 % |
| Divested Assets | — | 20 | (100)% | 14 | 42 | (67 )% |
| Total | 118 | 129 | (9 )% | 253 | 250 | 1 % |
| Ad valorem tax | 20 | 11 | 82 % | 32 | 25 | 28 % |
| Total oil, natural gas and NGL production expenses | $138 | $140 | (1 )% | $285 | $275 | 4 % |
| | ($ per boe) | | | | | |
| Marcellus | $0.59 | $0.44 | 34 % | $0.60 | $0.41 | 46 % |
| Haynesville | $1.09 | $1.12 | (3 )% | $1.19 | $1.04 | 14 % |
| Eagle Ford | $5.54 | $5.31 | 4 % | $5.36 | $5.09 | 5 % |
| Utica | $1.14 | $1.17 | (3 )% | $1.17 | $1.10 | 6 % |
| Mid-Continent | $9.23 | $11.77 | (22 )% | $10.59 | $12.30 | (14 )% |
| Powder River Basin | $5.52 | $4.32 | 28 % | $6.27 | $5.40 | 16 % |
| Retained Assets[(a)] | $2.44 | $2.45 | — % | $2.47 | $2.37 | 4 % |
| Divested Assets | $— | $6.15 | (100)% | $8.33 | $5.60 | 49 % |
| Total | $2.44 | $2.69 | (9 )% | $2.57 | $2.62 | (2 )% |
| Ad valorem tax | $0.42 | $0.23 | 83 % | $0.33 | $0.26 | 27 % |
| Total oil, natural gas and NGL production expenses per boe | $2.86 | $2.92 | (2 )% | $2.90 | $2.88 | 1 % |

(a) Includes assets retained as of June 30, 2018.

The absolute and per unit decrease in the Current Quarter was the result of the sale of certain oil and natural gas properties in 2017 and 2018, partially offset by an increase in salt water disposal cost primarily in Haynesville and Eagle Ford. The absolute and per unit increase in the Current Period was the result of increased salt water disposal cost in all operating areas and increased workover activity primarily in the Haynesville and Powder River Basin. Production expenses in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period included approximately $4 million, $5 million, $8 million and $11 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.

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Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | ($ in millions, except per unit) | | | |
| Oil, natural gas and NGL gathering, processing and transportation expenses | $340 | $357 | $696 | $712 |
| Oil ($ per bbl) | $3.22 | $3.70 | $3.70 | $3.77 |
| Natural gas ($ per mcf) | $1.29 | $1.37 | $1.28 | $1.36 |
| NGL ($ per bbl) | $8.46 | $7.87 | $8.65 | $8.16 |
| Total ($ per boe) | $7.04 | $7.44 | $7.10 | $7.45 |

The absolute and per unit decrease in oil, natural gas and NGL gathering, processing and transportation expenses was primarily due to lower gathering fees associated with restructured midstream contracts, lower volume commitments on downstream pipelines and certain 2018 and 2017 divestitures.

Production Taxes

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions, except per unit) | | | | | |
| Production taxes | $26 | $21 | 24 % | $57 | $43 | 33 % |
| Production taxes per boe | $0.55 | $0.42 | 31 % | $0.58 | $0.45 | 29 % |

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 June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions, except per unit) | | | | | |
| Gross overhead | $201 | $206 | (2 )% | $389 | $407 | (4 )% |
| Allocated to production expenses | (36 ) | (45 ) | (20 )% | (76 ) | (90 ) | (16 )% |
| Allocated to marketing expenses | (5 ) | (8 ) | (38 )% | (11 ) | (15 ) | (27 )% |
| Capitalized | (30 ) | (31 ) | (3 )% | (62 ) | (67 ) | (7 )% |
| Reimbursed from third parties | (39 ) | (52 ) | (25 )% | (77 ) | (100 ) | (23 )% |
| General and administrative expenses, net | $91 | $70 | 30 % | $163 | $135 | 21 % |
| | | | | | | |
| General and administrative expenses, net per boe | $1.89 | $1.45 | 30 % | $1.66 | $1.40 | 19 % |

Gross overhead decreased primarily due to our reduction in workforce offset by increased liability based awards. 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.

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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 Period 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 June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions, except per unit) | | | | | |
| Oil, natural gas and NGL depreciation, depletion and amortization | $271 | $202 | 34 % | $539 | $399 | 35 % |
| Oil, natural gas and NGL depreciation, depletion and amortization per boe | $5.61 | $4.21 | 33 % | $5.49 | $4.18 | 31 % |

The absolute and per unit increase in the Current Quarter and the Current Period is primarily the result of 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 reserve 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 June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions, except per unit) | | | | | |
| Depreciation and amortization of other assets | $19 | $21 | (10 )% | $37 | $42 | (12 )% |
| Depreciation and amortization of other assets per boe | $0.38 | $0.43 | (12 )% | $0.37 | $0.44 | (16 )% |

The absolute and per unit decrease in the Current Quarter and the Current Period was primarily the result of the sale of certain other assets.

Impairments

In the Current Quarter, we have determined that certain of our other fixed assets will either be sold or disposed before the end of their useful lives indicating the carrying value may not be recoverable. As a result, we recognized an impairment loss of $42 million in the Current Quarter for the difference between the carrying amount and fair value of the assets.

Other Operating (Income) Expense

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| | ($ in millions) | | | | | |
| Other operating (income) expense | $(1) | $ 26 | (104)% | $(1) | $417 | (100)% |

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

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Interest Expense

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| | ($ in millions) | | | |
| Interest expense on senior notes | $144 | $136 | $288 | $272 |
| Interest expense on term loan | 30 | 32 | 58 | 64 |
| Amortization of loan discount, issuance costs and other | 2 | 6 | 10 | 15 |
| Amortization of premium | (24) | (42) | (48) | (83) |
| Interest expense on revolving credit facility | 8 | 8 | 18 | 17 |
| Realized gains on interest rate derivatives[(a)] | — | (1) | (1) | (2) |
| Unrealized losses on interest rate derivatives[(b)] | — | 1 | 1 | 3 |
| Capitalized interest | (43) | (47) | (86) | (98) |
| Total interest expense | $117 | $93 | $240 | $188 |
| | | | | |
| Interest expense per boe[(c)] | $2.43 | $1.92 | $2.44 | $1.94 |
| | | | | |
| Average senior notes borrowings | $7,967 | $7,600 | $7,967 | $7,644 |
| Average credit facilities borrowings | $380 | $351 | $488 | $176 |
| Average term loan borrowings | $1,233 | $1,500 | $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.

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

The increase in interest expense is primarily due to the increase in the average outstanding principal amount of senior notes and 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 our senior secured 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.

Gains on Investments

In the Current Period, we recognized $139 million of gains related to our equity investment in FTSI, including the sale of a portion of that investment. See Note 11 of the notes to our condensed consolidated financial statements included in Item 1 of this report for further discussion.

Losses on Purchases or Exchanges of Debt

In the Prior Quarter, we retired $682 million principal amount of our outstanding senior secured second lien notes through a tender offer for $750 million. We recorded an aggregate gain of approximately $191 million associated with the transaction.

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

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Other Income (Expense)

In the Current Quarter, we extinguished our obligation to convey future ORRIs to the CHK Utica L.L.C. investors and recognized a $61 million gain included in other income on our condensed consolidated statement of operations. See Note 5 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of the transaction.

Income Tax Expense (Benefit)

We recorded a $9 million income tax benefit in the Current Quarter and in the Current Period and recorded $1 million and $2 million of income tax expense in the Prior Quarter and in the Prior Period, respectively. Our effective income tax rate was 36.0% for the Current Quarter, and (3.3%) for the Current Period compared to 0.2% and 0.3% for the Prior Quarter and for the Prior Period, respectively. Our effective tax rate can fluctuate as a result of the impact of discrete items, state income taxes and permanent differences. For the Current Quarter, our estimated annual effective tax rate remains nominal as a result of having a full valuation allowance against our net deferred tax asset. 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, the closing of the sale of our Utica interests and the amount and expected use of proceeds of the sale and the other items discussed in 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;
- effects of purchase price adjustments and indemnity obligations;
- the need to obtain certain consents and approvals and satisfy certain conditions to closing of the Utica transaction, which may not be completed in the anticipated time frame or at all;
- the occurrence of any event or other circumstance that could lead to the termination of the agreement governing the sale of our Utica interests; 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.

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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 June 30, 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.

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As of June 30, 2018, we had the following open oil, natural gas and NGL derivative instruments:

| | | Weighted Average Price | | | | Fair Value |
|---|---|---|---|---|---|---|
| | Volume | Fixed | Call | Put | Differential | Asset (Liability) |
| | (mmbbl) | ($ per bbl) | | | | ($ in millions) |
| Oil: | | | | | | |
| Swaps: | | | | | | |
| Short-term | 20 | $56.35 | $— | $ — | $ — | $ (246 ) |
| Long-term | 6 | $59.96 | $— | $ — | $ — | (25 ) |
| Three-Way Collars: | | | | | | |
| Short-term | 1 | $— | $55.00 | 39.15/47.00 | $ — | (14 ) |
| Call Swaptions: | | | | | | |
| Short-term | 2 | $52.87 | $— | $ — | $ — | (32 ) |
| Basis Protection Swaps: | | | | | | |
| Short-term | 9 | $— | $— | $ — | $ 4.11 | 2 |
| Long-term | 2 | $— | $— | $ — | $ 6.20 | 4 |
| Total Oil | | | | | | (311 ) |

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| | Volume | Weighted Average Price Fixed | Call | Put | Differential | Fair Value Asset (Liability) |
|---|---|---|---|---|---|---|
| | (bcf) | ($ per mcf) | | | | |
| Natural Gas: | | | | | | |
| Swaps[(a)]: | | | | | | |
| Short-term | 240 | $2.97 | $— | $ — | $ | —3 |
| Three-Way Collars: | | | | | | |
| Short-term | 43 | — | $3.10 | 2.50/2.80 | — | — |
| Long-term | 44 | — | $3.10 | 2.50/2.80 | — | — |
| Collars: | | | | | | |
| Short-term | 24 | $— | $3.25 | $ 3.00 | $ | —2 |
| Call Options (sold): | | | | | | |
| Short-term | 44 | $— | $7.68 | $ — | $ | —— |
| Long-term | 33 | $— | $12.00 | $ — | $ | —— |
| Basis Protection Swaps: | | | | | | |