UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

**Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934**

Date of Report (Date of earliest event reported): May 9, 2019

CHESAPEAKE ENERGY CORPORATION

(Exact name of Registrant as specified in its Charter)

Oklahoma	**1-13726**	**73-1395733**
(State or other jurisdiction of incorporation)	(Commission File No.)	(IRS 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)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§ 230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§ 240.12b-2 of this chapter).

Emerging growth company o

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. o

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	**Trading Symbols**	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01	CHK	New York Stock Exchange
6.625% Senior Notes due 2020	CHK20A	New York Stock Exchange
6.875% Senior Notes due 2020	CHK20	New York Stock Exchange
6.125% Senior Notes due 2021	CHK21	New York Stock Exchange
5.375% Senior Notes due 2021	CHK21A	New York Stock Exchange
4.875% Senior Notes due 2022	CHK22	New York Stock Exchange
5.75% Senior Notes due 2023	CHK23	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	CHK Pr D	New York Stock Exchange

Item 8.01 Other Events.

During the first quarter of 2019, Chesapeake Energy Corporation (the "Company", "We" or "Us") voluntarily changed our method of accounting for oil and natural gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, certain financial information for prior periods has been recast to reflect retrospective application of the successful efforts method.

We have recast certain information in this filing to reflect the retrospective application of this change in accounting principle for all periods presented in the following sections of our Annual Report on Form 10-K for the year ended December 31, 2018 (the "Previously Filed Annual Report") as follows:

- Part II, Item 6. Selected Financial Data,
- Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and
- Part II, Item 8. Financial Statements and Supplementary Data.

As this Current Report on Form 8-K is being filed only for the purpose described above, and only affects the Items specified above, the other information in the Previously Filed Annual Report filed with the Securities Exchange Commission (the "SEC") on February 27, 2019 remains unchanged. No attempt has been made in this Current Report on Form 8-K to modify or update disclosures in the Previously Filed Annual Report, except for the revision of certain financial information as described above. This Current Report on Form 8-K does not reflect events occurring after the filing of the Previously Filed Annual Report. Accordingly, this Current Report on Form 8-K should be read in conjunction with the Previously Filed Annual Report and the Company's filings made with the SEC subsequent to the filing of the Previously Filed Annual Report, including any amendments to those filings.

Item 9.01 Financial Statements and Exhibits.

(d)

Exhibit No.	Document Description
23.1	Consent of PricewaterhouseCoopers LLP.
99.1	Selected Financial Data, Management's Discussion and Analysis of Financial Condition and Results of Operations and Financial Statements and Supplementary Data of our Annual Report on Form 10-K for the year ended December 31, 2018.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.CAL	XBRL Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.
101.LAB	XBRL Label Linkbase Document.
101.PRE	XBRL Presentation Linkbase Document.

SIGNATURE

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

CHESAPEAKE ENERGY CORPORATION

By: /s/ JAMES R. WEBB

James R. Webb

Executive Vice President - General Counsel and Corporate Secretary

Date: May 9, 2019

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 333-126191, 333-135949, 333-143990, 333-151762, 333-160350, 333-171468, 333-178067, 333-187018, 333-189651, 333-192175, 333-196977 and 333-214683) and Form S-3 (File No. 333-219649) of Chesapeake Energy Corporation of our report dated February 27, 2019, except with respect to our opinion on the consolidated financial statements insofar as it relates to the change in the manner in which the Company accounts for oil and natural gas exploration and development activities discussed in Notes 1 and 2, as to which the date is May 9, 2019, relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Current Report on Form 8-K.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
May 9, 2019

PART II

Exhibit 99.1

CHESAPEAKE ENERGY CORPORATION

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of Chesapeake as of and for the years ended December 31, 2018, 2017, 2016, 2015 and 2014. The financial data from 2018, 2017 and 2016 are derived from our audited consolidated financial statements. The financial data from 2015 and 2014 are derived from our recast financial statements not included in this 8-K. The table below should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements, including the notes thereto, appearing in Items 7 and 8, respectively, of this report. Financial information for all periods has been recast to reflect retrospective application of the successful efforts method of accounting. See Notes 1 and 2 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the change in accounting principle.

	Years Ended December 31,				
	2018	2017	2016	2015	2014
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA:					
Total revenues	$ 10,030	$ 10,039	$ 8,705	$ 13,794	$ 26,936
Net income (loss) available to common stockholders[(a)]	$ 133	$ (631)	$ (4,018)	$ (11,383)	$ 1,372
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 0.15	$ (0.70)	$ (5.26)	$ (17.18)	$ 2.08
Diluted	$ 0.15	$ (0.70)	$ (5.26)	$ (17.18)	$ 2.00
CASH DIVIDEND DECLARED PER COMMON SHARE	$ —	$ —	$ —	$ 0.0875	$ 0.35
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 12,735	$ 14,925	$ 17,048	$ 21,432	$ 41,562
Long-term debt, net of current maturities	$ 7,341	$ 9,921	$ 9,938	$ 10,311	$ 11,058
Total equity (deficit)	$ 2,133	$ 1,943	$ 2,565	$ 5,256	$ 17,705

(a) Includes $131 million, $814 million, $563 million, $11.590 billion and $1.380 billion of impairments of oil and gas properties and other fixed assets for the years ended December 31, 2018, 2017, 2016, 2015 and 2014, respectively.

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Overview

During the first quarter of 2019, we changed our method of accounting for our oil and natural gas exploration and development activities from the full cost method to the successful efforts method of accounting. Financial information for all periods has been recast to reflect retrospective application of the successful efforts method of accounting. See Note 1 of the notes to our consolidated financial statements included in Item 8 of this 8-K for further discussion of the change in accounting principle.

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" of this report.

The transformation of Chesapeake over the past five years has been significant and our progress accelerated in 2018 and early 2019. We believe our recent accomplishments and achievements have made our company stronger.

Highlights include the following:

- acquired WildHorse, an oil and gas company with operations in the Eagle Ford Shale and Austin Chalk formations in southeast Texas, for approximately 717.3 million shares of our common stock and $381 million in cash, and the assumption of WildHorse's debt of $1.4 billion as of February 1, 2019. We anticipate the acquisition to materially increase our oil production and enhance our oil production mix as well as significantly reduce costs due to operational synergies that we believe the combined company will achieve. We expect that the WildHorse Merger will provide substantial cost savings with $200 million to $280 million in projected average annual savings, totaling $1 billion to $1.5 billion by 2023, due to operational and capital efficiencies as a result of Chesapeake's significant expertise with unconventional assets and technical and operational excellence;
- sold our interests in the Utica Shale operating area located in Ohio for approximately $1.9 billion, and used the proceeds to reduce outstanding debt by approximately $1.8 billion, including our senior secured second lien notes;
- retired our secured term loan due 2021 and significantly extended our debt maturity profile by issuing at par $850 million of 7.00% Senior Notes due 2024 and $400 million of 7.50% Senior Notes due 2026 for net proceeds of $1.2 billion, reducing our annual cash interest by approximately $30 million based on interest rates at the time of retirement;
- continued to simplify our balance sheet, by repurchasing the CHK Utica, L.L.C. investors' overriding royalty interests (ORRI) for $199 million;
- improved liquidity by amending and restating our Chesapeake revolving credit facility, extending its maturity date by approximately four years;
- improved cash flow from operations by $1.3 billion;
- improved our cost structure by reducing our production, general and administrative, and gathering, processing and transportation expenses by $94 million, or 4%; and
- generated approximately $528 million in proceeds from the disposition of certain non-core assets and other property sales in addition to the sale of our Utica Shale properties.

Looking forward into 2019, we are confident in our ability to drive further competitive performance through the quality of our investments and our capital and operating discipline. We have secured a strong hedge position for oil and natural gas that provides stability and certainty in our cash generating capability should commodity prices experience volatility.

In 2019, our focus remains concentrated on four strategic priorities:

- reduce total leverage to achieve long term net debt/EBITDAX of 2x;
- increase net cash provided by operating activities to fund capital expenditures;
- improve margins through financial discipline and operating efficiencies; and
- maintain industry leading environmental and safety performance.

Business and Industry Outlook

Over the past decade, the landscape of energy production has changed dramatically in the United States. Domestic energy production capabilities have increased the nation's supply of both crude oil and natural gas, primarily driven by advances in technology, horizontal drilling and hydraulic fracture stimulation techniques. As a result of this increase in domestic supply of crude oil and natural gas, commodity prices for these products are meaningfully lower than they were a decade ago, and may remain volatile for the foreseeable future.

We have undergone a mutli-year effort to reduce our cost structure significantly and improve the profitability of our upstream portfolio. We have sold our non-upstream businesses, assets in under-performing basins and reduced our operating and general and administrative costs such that we are currently experiencing higher profitability than compared to periods when commodity prices were much higher. The improvements in our cost structure give us a strategic advantage as a low cost developer of unconventional oil and gas assets in the U.S. We recently used this strategic advantage to successfully acquire WildHorse, a single asset, oil-focused company with an attractive acreage position of high-margin, undrilled locations. Our strategy going forward will be to leverage our advantages to drive shareholder value by growing cash flow through the development of our extensive portfolio of drilling opportunities. We intend to maintain capital discipline as we target cash flow growth rates that can be sustainable with internally generated resources.

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 volatile, and may be subject to wide fluctuations in the future. A decline in oil, natural gas and NGL prices could negatively affect the amount of cash we generate and have available for capital expenditures and debt service and could have a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we can economically produce or provide as collateral to our credit facility lenders. Other risks and uncertainties that could affect our liquidity include, but are not limited to, counterparty credit risk for our receivables, access to capital markets, regulatory risks and our ability to meet financial covenants in our financing agreements.

Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facilities, we expect to be able to fund our planned capital expenditures, meet our debt service requirements and fund our other commitments and obligations for the next 12 months.

As of December 31, 2018, we had a cash balance of $4 million compared to $5 million as of December 31, 2017, and a net working capital deficit of $1.289 billion as of December 31, 2018, compared to a net working capital deficit of $893 million as of December 31, 2017. As of December 31, 2018, our working capital deficit includes $381 million of debt due in the next 12 months. Our total principal debt as of December 31, 2018 was $8.168 billion compared to $9.981 billion as of December 31, 2017. As of December 31, 2018, we had $2.474 billion of borrowing capacity available under the Chesapeake revolving credit facility, with outstanding borrowings of $419 million and $107 million utilized for various letters of credit. As of the WildHorse acquisition date of February 1, 2019, we had $578 million of borrowing capacity available under the WildHorse revolving credit facility, with outstanding borrowings of $675 million and $47 million utilized as a letter of credit. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our debt obligations, including principal and carrying amounts of our notes.

Although we have taken measures to mitigate liquidity concerns over the next 12 months, as outlined above in *Overview*, 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 facilities. Furthermore, our ability to generate operating cash flow in the current commodity price environment, sell assets, access capital markets or take any other action to improve our liquidity and manage our debt is subject to the risks discussed above and the other risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

Derivative and Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. To mitigate a portion of the 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 predict with greater certainty the total revenue we will receive.

We utilize various oil, natural gas and NGL derivative instruments to protect a portion of our cash flow against downside risk. As of February 22, 2019, including January and February derivative contracts that have settled, approximately 63% of our forecasted oil, natural gas and NGL production revenue was hedged, including 56% and 81% of our forecasted 2019 oil and natural gas production (including WildHorse production from February 1, 2019) at average prices of $57.12 per barrel and $2.85 per mcf, respectively.

Oil Derivatives[a]

Year	Type of Derivative Instrument	Notional Volume	Average NYMEX Price
		(mmbbls)	
2019	Swaps	17	$57.16
2019	Two-way collars	6	$58.00/$67.75
2019	Basis protection swaps	7	$6.01
2019	Puts	2	$53.83
2020	Swaps	7	$58.28
2020	Two-way collars	2	$65.00/$83.25

Natural Gas Derivatives[a]

Year	Type of Derivative Instrument	Notional Volume	Average NYMEX Price
		(bcf)	
2019	Swaps	453	$2.87
2019	Two-way collars	55	$2.75/$3.02
2019	Three-way collars	88	$2.50/$2.80/$3.10
2019	Calls	22	$12.00
2019	Basis protection swaps	50	($0.56)
2020	Swaps	217	$2.75
2020	Call swaptions	106	$2.77
2020	Calls	22	$12.00

(a) Includes amounts settled in January and February 2019.

See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of derivatives and hedging activities.

Debt

We decreased our total principal amount of debt outstanding by approximately $1.8 billion in 2018. We accomplished this primarily by using the net proceeds from the sale of our Utica interests and other assets. We currently plan to use cash flow from operations and availability under our credit facilities to fund our capital expenditures for 2019. 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.

In 2018, we issued at par $850 million of 7.00% Senior Notes due 2024 (the “2024 notes”) and $400 million of 7.50% Senior Notes due 2026 (the “2026 notes” and, together with the 2024 notes, the “senior notes”) pursuant to a public offering for net proceeds of approximately $1.236 billion. We may redeem some or all of the 2024 notes at any time prior to April 1, 2021 and some or all of the 2026 notes at any time prior to October 1, 2021, in each case at a price equal to 100% of the principal amount of the notes to be redeemed plus a “make-whole” premium.

We used the net proceeds from the senior notes, together with cash on hand and borrowings under the Chesapeake revolving credit facility, to repay in full $1.233 billion of borrowings under our secured term loan due 2021 for $1.285 billion, which included a $52 million make-whole premium. We recorded a loss of approximately $65 million associated with the repayment of the term loan, including the make-whole premium and the write-off of $13 million of associated deferred charges. Also in 2018, we used the proceeds from the sale of our Utica assets in Ohio to redeem all of the $1.416 billion aggregate principal amount outstanding of our 8.00% Senior Secured Second Lien Notes due 2022 which included a $60 million make-whole premium. We recorded a gain of approximately $331 million associated with the redemption, including the realization of the remaining $391 million difference in principal and book value due to troubled debt restructuring accounting in 2015, offset by the make-whole premium of $60 million.

We may continue to use a combination of cash, borrowings and issuances of our common stock or other securities to retire our outstanding debt, including any debt assumed in connection with the completion with the WildHorse acquisition, through privately negotiated transactions, open market repurchases, redemptions, tender offers or otherwise, but we are under no obligation to do so. We expect to generate additional liquidity with proceeds from future sales of assets that do not fit our strategic priorities.

Chesapeake Revolving Credit Facility

The Chesapeake revolving credit facility is currently subject to a $3.0 billion borrowing base that matures in September 2023. As of December 31, 2018, we had $2.474 billion of borrowing capacity available under the Chesapeake revolving credit facility. Our next borrowing base redetermination is scheduled for the second quarter of 2019. As of December 31, 2018, we had outstanding borrowings of $419 million under the Chesapeake revolving credit facility and had used $107 million of the Chesapeake revolving credit facility for various letters of credit. Borrowings under the facility bear interest at a variable rate. Under the Chesapeake revolving credit facility, we borrowed $11.697 billion and repaid $12.059 billion in 2018, we borrowed $7.771 billion and repaid $6.990 billion in 2017 and we borrowed and repaid $5.146 billion in 2016. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the terms of the Chesapeake revolving credit facility. As of December 31, 2018, we were in compliance with all applicable financial covenants under the credit agreement. Our leverage ratio, calculated under the full cost method, was approximately 3.31 to 1.00. Our secured leverage ratio and fixed charge coverage ratio were not in effect for the quarter ended December 31, 2018, due to the Utica Shale divestiture taking place during the quarter. Both ratios, in addition to the leverage ratio, will be in effect for the quarter ending March 31, 2019.

WildHorse Revolving Credit Facility

In connection with the acquisition of WildHorse, our subsidiary Brazos Valley Longhorn became the borrower under the WildHorse revolving credit facility. The WildHorse revolving credit facility has a maximum credit amount of $2.0 billion, with current aggregate elected commitments of $1.3 billion and a current borrowing base of $1.3 billion. The WildHorse revolving credit facility matures in December 2021. The borrowing base under the WildHorse revolving credit facility is subject to redetermination, on at least a semi-annual basis, primarily on estimated proved reserves. The next scheduled redetermination is in the second quarter of 2019. As of the WildHorse acquisition date of February 1, 2019, we had $578 million of borrowing capacity available under the WildHorse revolving credit facility, with outstanding borrowings of $675 million and $47 million utilized as a letter of credit. The WildHorse revolving credit facility is guaranteed by certain of Brazos Valley Longhorn’s subsidiaries (the “BVL Guarantors”) and is required to be secured by substantially all of the assets of Brazos Valley Longhorn and BVL Guarantors, including mortgages on not less than 85% of the proved reserves of their oil and gas properties.

The obligations under the WildHorse revolving credit facility are the senior secured obligations of Brazos Valley Longhorn and the BVL Guarantors. The obligations under the WildHorse revolving credit facility will not be obligations of Chesapeake or any of its subsidiaries other than Brazos Valley Longhorn and the BVL Guarantors. The obligations under the WildHorse revolving credit facility will rank equally in right of payment with all other senior secured indebtedness of Brazos Valley Longhorn and the other BVL Guarantors, and will be effectively senior to Brazos Valley Longhorn's and the BVL Guarantors' senior unsecured indebtedness, including their obligations under the WildHorse senior notes, to the extent of the value of the collateral securing the WildHorse revolving credit facility.

The Wildhorse revolving credit facility is used for the liquidity and expenses of Brazos Valley Longhorn and its subsidiaries and not Chesapeake or any of its subsidiaries other than Brazos Valley Longhorn, Brazos Valley Longhorn Finance Corp. ("BVL Finance Corp.") and the other BVL Guarantors. Revolving loans under the WildHorse revolving credit facility bear interest at the alternate base rate, Eurodollar rate or LIBOR market index rate at Brazos Valley Longhorn's election, plus an applicable margin (ranging from 0.50%-1.50% per annum for alternate base rate loans, 1.50%-2.50% per annum for Eurodollar loans and 1.50%-2.50% per annum for LIBOR market index rate loans), depending on Brazos Valley Longhorn's total commitment usage. The unused portion of the total commitments are subject to a commitment fee that varies from 0.375% to 0.500%, depending on Brazos Valley Longhorn's total commitment usage. The terms of the WildHorse revolving credit facility include covenants limiting, among other things, the ability of Brazos Valley Longhorn and its Restricted Subsidiaries (as defined under the WildHorse revolving credit facility) to incur additional indebtedness, make investments or loans, incur liens, consummate mergers or similar fundamental changes, make restricted payments, including dividends to Chesapeake, and enter into transactions with affiliates, including Chesapeake and its other subsidiaries. The WildHorse revolving credit facility also contains financial covenants that require Brazos Valley Longhorn to maintain (i)(x) if there are no loans outstanding thereunder, a ratio of net debt to EBITDAX (as defined under the WildHorse revolving credit facility) of not more than 4.00 to 1.00 as of the last day of each fiscal quarter or (y) if there are such loans outstanding, a ratio of total debt to EBITDAX of not more than 4.00 to 1.00 as of the last day of each fiscal quarter and (ii) a ratio of current assets (including availability under the WildHorse revolving credit facility) to current liabilities of not less than 1.00 to 1.00 as of the last day of each fiscal quarter. As of December 31, 2018, WildHorse was in compliance with all applicable financial covenants under the credit agreement. WildHorse's ratio of net debt to EBITDAX was 1.81 to 1.00 and our ratio of current assets was 4.30 to 1.00 as of December 31, 2018.

The WildHorse revolving credit facility includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; defaults with respect to indebtedness in an aggregate principal amount of $25.0 million or more; bankruptcy; judgments involving liability of $15.0 million or more that are not paid; change of control; and ERISA events. Many events of default are subject to customary notice and cure periods.

WildHorse Senior Notes

As a result of the completion of the acquisition of WildHorse, Brazos Valley Longhorn assumed the obligations under WildHorse's $700 million aggregate principal amount of 6.875% Senior Notes due 2025 (the "WildHorse senior notes") and BVL Finance Corp., a wholly owned subsidiary of Brazos Valley Longhorn, became a co-issuer of the WildHorse senior notes.

The WildHorse senior notes are the senior unsecured obligations of Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors. The WildHorse senior notes will not be obligations of Chesapeake or any of its subsidiaries other than Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors. The WildHorse senior notes will rank equally in right of payment with all other senior unsecured indebtedness of Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors, and will be effectively subordinated to Brazos Valley Longhorn's, BVL Finance Corp.'s and the other BVL Guarantors' senior secured indebtedness, including their obligations under the WildHorse revolving credit facility, to the extent of the value of the collateral securing such indebtedness.

The indenture (the “WildHorse indenture”) governing the WildHorse senior notes contains customary reporting covenants (including furnishing quarterly and annual reports to the holders of the WildHorse senior notes) and restrictive covenants that, among other things, restrict the ability of Brazos Valley Longhorn and its subsidiaries to: (i) pay dividends on, purchase or redeem Brazos Valley Longhorn’s equity interests or purchase or redeem subordinated debt; (ii) make certain investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create or incur certain secured debt; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of Brazos Valley Longhorn’s assets; (vii) enter into agreements that restrict distributions or other payments from Brazos Valley Longhorn’s restricted subsidiaries to Brazos Valley Longhorn; (viii) engage in transactions with affiliates, including Chesapeake and its other subsidiaries; and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important qualifications and limitations. In addition, most of the covenants will be terminated before the WildHorse senior notes mature if at any time no default or event of default exists under the WildHorse indenture and the WildHorse senior notes receive an investment grade rating from both of two specified ratings agencies. The WildHorse indenture also contains customary events of default.

If the WildHorse senior notes are downgraded within 90 days after the consummation of the acquisition of WildHorse (which constitutes a “Change of Control” under the WildHorse indenture), the WildHorse indenture requires Brazos Valley Longhorn (or a third party, in certain circumstances) to make an offer to repurchase the WildHorse senior notes at 101% of their principal amount, plus accrued and unpaid interest, within 30 days of such downgrade. If any holder of WildHorse senior notes accepts such offer, Brazos Valley Longhorn may (subject to the terms and conditions thereof) fund the purchase price with loans under the WildHorse revolving credit facility or Chesapeake may elect to draw under the Chesapeake revolving credit facility, use cash on hand, issue debt securities or use other sources of liquidity to fund such repurchase. If Brazos Valley Longhorn and Chesapeake are not required to make such offer or not all holders of WildHorse senior notes accept such an offer, Chesapeake may seek to amend, engage in liability management transactions with respect to, or redeem or refinance, the WildHorse senior notes at any time.

The WildHorse revolving credit facility and the WildHorse Indenture constrain the ability of WildHorse and its subsidiaries to make distributions or otherwise provide funds to, or guarantee the obligations of, Chesapeake and its other subsidiaries. The provisions of the WildHorse revolving credit facility and the WildHorse Indenture require that all transactions between WildHorse and its subsidiaries, on the one hand, and Chesapeake and its other subsidiaries, on the other hand, be on an arm's-length basis.

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. The table below summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2018:

	Payments Due By Period				
	Total	**2019**	**2020-2021**	**2022-2023**	**2024 and Beyond**
			($ in millions)		
Long-term debt:[a]					
Principal[b]	$ 8,168	$ 381	$ 1,479	$ 1,208	$ 5,100
Interest	3,058	523	942	793	800
Capital lease obligation[c]	30	10	20	—	—
Operating lease obligations[d]	4	3	1	—	—
Operating commitments[e]	5,786	837	1,467	1,051	2,431
Unrecognized tax benefits[f]	53	—	—	53	—
Standby letters of credit	107	107	—	—	—
VPP obligation[g]	122	59	63	—	—
Other	18	4	8	6	—
Total contractual cash obligations[h]	$ 17,346	$ 1,924	$ 3,980	$ 3,111	$ 8,331

(a) We assumed $1.4 billion of debt with the completion of the WildHorse acquisition on February 1, 2019 that is not included in the table above.

(b) See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our long-term debt.

(c) See Note 7 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our capital lease obligation.

(d) See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our operating lease obligations.

(e) See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our gathering, processing and transportation agreements and service contract commitments.

(f) See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of unrecognized tax benefits.

(g) See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our VPP obligation.

(h) This table does not include derivative liabilities or the estimated discounted liability for future dismantlement, abandonment and restoration costs of oil and natural gas properties. See Notes 14 and 23, respectively, of the notes to our consolidated financial statements included in Item 8 of this report for more information on our derivatives and asset retirement obligations.

Capital Expenditures

Our 2019 capital expenditures program is expected to generate greater capital efficiency than the 2018 program as we focus on expanding our margins through disciplined 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 2019 capital expenditures, inclusive of Brazos Valley and capitalized interest, are $2.1 – $2.3 billion compared to our 2018 capital spending level of $2.1 billion. Management continues to review operational plans for 2019 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL.

Credit Risk

Derivative instruments that enable us to manage our exposure to oil, natural gas and NGL prices expose us to credit risk from our counterparties. To mitigate this risk, we enter into oil, natural gas and NGL derivative contracts only with counterparties that we deem to have acceptable credit strength and are 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 December 31, 2018, our oil, natural gas and NGL derivative instruments were spread among 11 counterparties. Additionally, the counterparties under these arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($976 million as of December 31, 2018) and exploration and production companies that own interests in properties we operate ($211 million as of December 31, 2018). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2018, 2017 and 2016, we recognized $6 million, $9 million and $10 million, respectively, of bad debt expense related to potentially uncollectible receivables.

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 February 22, 2019, we have received requests and posted approximately $162 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 $355 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 years ended December 31, 2018, 2017 and 2016. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of divestitures of oil and natural gas assets.

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Cash provided by (used in) operating activities	$ 1,730	$ 475	$ (980)
Proceeds from issuances of debt, net	1,236	1,585	3,686
Proceeds from revolving credit facility borrowings, net	—	781	—
Proceeds from divestitures of proved and unproved properties, net	2,231	1,249	1,406
Proceeds from sales of other property and equipment, net	147	55	131
Proceeds from sales of investments	74	—	—
Total sources of cash and cash equivalents	$ 5,418	$ 4,145	$ 4,243

Cash Flow from Operating Activities

Cash provided by operating activities was $1.730 billion in 2018 compared to cash provided by operating activities of $475 million in 2017 and cash used in operating activities of $980 million in 2016. The increase in 2018 is primarily the result of higher prices for the oil, natural gas and NGL we sold. The increase in 2017 is primarily the result of higher prices for the oil, natural gas and NGL we sold and decreases in certain of our operating expenses, partially offset by lower volumes of oil, natural gas and NGL sold, the payment related to the litigation involving the early redemption of our 6.775% Senior Notes due 2019 and payments for terminations of transportation contracts. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items, such as depreciation, depletion and amortization, 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*.

Debt issuances

The following table reflects the proceeds received from issuances of debt in 2018, 2017 and 2016. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

	Years Ended December 31,					
	2018		2017		2016	
	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds
	($ in millions)					
Senior notes	$ 1,250	$ 1,236	$ 1,600	$ 1,585	$ 1,000	$ 975
Convertible senior notes	—	—	—	—	1,250	1,235
Term loans	—	—	—	—	1,500	1,476
Total	$ 1,250	$ 1,236	$ 1,600	$ 1,585	$ 3,750	$ 3,686

Divestitures of Proved and Unproved Properties

During 2018, we divested $2.231 billion of proved and unproved properties including $1.868 billion for all of our Utica Shale properties in Ohio. During 2017 and 2016, we divested certain non-core assets for approximately $1.249 billion and $1.406 billion, respectively. Proceeds from these transactions were used to repay debt and fund our development program. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Oil and Natural Gas Expenditures:			
Drilling and completion costs	$ 1,848	$ 2,113	$ 1,192
Acquisitions of proved and unproved properties	128	88	115
Total oil and natural gas expenditures	1,976	2,201	1,307
Other Uses of Cash and Cash Equivalents:			
Cash paid to purchase debt	2,813	2,592	2,734
Payments on revolving credit facility borrowings, net	362	—	—
Extinguishment of other financing	122	—	—
Additions to other property and equipment	21	21	37
Cash paid for preferred stock dividends	92	183	—
Distributions to noncontrolling interest owners	6	8	10
Other	27	17	98
Total other uses of cash and cash equivalents	3,443	2,821	2,879
Total uses of cash and cash equivalents	$ 5,419	$ 5,022	$ 4,186

Drilling and Completion Costs

Our drilling and completion costs decreased in 2018 compared to 2017 primarily as a result of decreased completion activity. We completed 351 operated wells in 2018 compared to 401 in 2017.

Cash Paid to Purchase Debt

In 2018, we used $2.813 billion of cash to repurchase $2.701 billion principal amount of debt. In 2017, we used $2.592 billion of cash to repurchase $2.389 billion principal amount of debt. In 2016, we used $2.734 billion of cash to repurchase $2.884 billion principal amount of debt.

Extinguishment of Other Financing

In 2018, 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 6 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the transaction.

Dividends

We paid dividends of $92 million on our preferred stock during 2018 and paid dividends of $183 million on our preferred stock in 2017, including $92 million of dividends in arrears that had been suspended throughout 2016. We did not pay dividends on our preferred stock in 2016. We eliminated common stock dividends in the 2015 third quarter and do not intend to resume paying cash dividends on our common stock in the foreseeable future.

Results of Operations

Oil, Natural Gas and NGL Production and Average Sales Prices

	2018								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	828	3.06	—	—	138	26	18.38
Haynesville	—	—	789	2.90	—	—	131	25	17.43
Eagle Ford	60	69.01	137	3.46	20	25.57	103	20	49.93
Powder River Basin	11	63.38	64	2.91	4	26.83	25	5	38.20
Mid-Continent	9	63.93	64	2.76	5	26.43	25	5	36.23
Retained assets[(a)]	80	67.67	1,882	3.01	29	25.88	422	81	27.98
Divested assets[(b)]	10	63.72	396	2.90	23	27.26	99	19	24.26
Total	90	67.25	2,278	2.99	52	26.50	521	100%	27.27

	2017								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	804	2.45	—	—	134	24	14.67
Haynesville	—	—	784	2.85	—	—	131	24	17.10
Eagle Ford	59	52.34	142	3.30	18	22.95	100	18	39.24
Powder River Basin	6	49.97	37	3.01	3	27.33	15	3	32.57
Mid-Continent	8	49.24	69	2.79	5	22.99	25	5	28.77
Retained assets[(a)]	73	51.78	1,836	2.71	26	23.37	405	74	23.07
Divested assets[(b)]	17	47.87	570	2.92	31	23.02	143	26	22.34
Total	90	51.03	2,406	2.76	57	23.18	548	100%	22.88

	2016								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	730	1.56	—	—	121	19	9.31
Haynesville	—	—	681	2.31	—	—	114	18	13.87
Eagle Ford	56	42.19	140	2.61	17	14.85	97	15	30.97
Powder River Basin	6	39.58	37	2.36	3	17.27	15	3	24.78
Mid-Continent	5	42.47	39	2.27	3	16.71	14	2	23.55
Retained assets[(a)]	67	41.98	1,627	2.00	23	15.26	361	57	17.76
Divested assets[(b)]	24	36.89	1,240	2.13	44	14.50	274	43	15.13
Total	91	40.65	2,867	2.05	67	14.76	635	100%	16.63

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

(b) Divested assets include Barnett, Devonian and certain Mid-Continent assets in 2016, certain Haynesville assets in 2017 and Utica assets in Ohio in 2018.

Oil, Natural Gas and NGL Sales

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions)				
Oil	$ 2,201	32%	$ 1,668	23%	$ 1,351
Natural gas	2,486	3%	2,422	12%	2,155
NGL	502	4%	484	34%	360
Oil, natural gas and NGL sales	$ 5,189	13%	$ 4,574	18%	$ 3,866

2018 vs. 2017. The increase in the price received per boe in 2018 resulted in an $836 million increase in revenues, and decreased sales volumes resulted in a $221 million decrease in revenues, for a total net increase in revenues of $615 million.

2017 vs. 2016. The increase in the price received per boe in 2017 resulted in a $1.250 billion increase in revenues, and decreased sales volumes resulted in a $542 million decrease in revenues, for a total net increase in revenues of $708 million.

See Note 8 of the notes to our consolidated financial statements included in Item 8 of this report for a complete discussion of oil, natural gas and NGL sales.

Oil, Natural Gas and NGL Derivatives

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Oil derivatives – realized gains (losses)	$ (321)	$ 70	$ 97
Oil derivatives – unrealized gains (losses)	445	(134)	(318)
Total gains (losses) on oil derivatives	124	(64)	(221)
Natural gas derivatives – realized gains (losses)	7	(9)	151
Natural gas derivatives – unrealized gains (losses)	(154)	489	(500)
Total gains (losses) on natural gas derivatives	(147)	480	(349)
NGL derivatives – realized gains (losses)	(13)	(4)	(8)
NGL derivatives – unrealized gains (losses)	2	(1)	—
Total gains (losses) on NGL derivatives	(11)	(5)	(8)
Total gains (losses) on oil, natural gas and NGL derivatives	$ (34)	$ 411	$ (578)

See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for a complete discussion of our derivative activity.

Marketing Revenues and Expenses

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions)				
Marketing revenues	$ 5,076	13%	$ 4,511	(2)%	$ 4,584
Marketing expenses	5,158	12%	4,598	(4)%	4,778
Marketing gross margin	$ (82)	6%	$ (87)	55 %	$ (194)

2018 vs. 2017. Marketing revenues and expenses increased in 2018 primarily as a result of increased oil, natural gas and NGL prices received in our marketing operations. Gross margin was negatively impacted by downstream pipeline delivery commitments.

2017 vs. 2016. Marketing revenues and expenses decreased in 2017 primarily as a result of decreased oil, natural gas and NGL prices received in our marketing operations. Gross margin increased primarily as a result of the reversal of cumulative unrealized gains associated with the termination of a supply contract derivative in 2016 as well as the sale of a significant portion of our gathering and compression assets in 2016.

Other Revenue

	Years Ended December 31,		
	2018	**2017**	**2016**
		($ in millions)	
Other revenue	$ 63	$ 67	$ 207

Other revenue relates to the amortization of deferred VPP revenue. Our remaining deferred revenue balance of $122 million will be amortized on a straight-line basis through 2021. The decrease in other revenue from 2016 to 2017 is a result of our purchase in 2016 of the remaining oil and natural gas interests previously sold in connection with five of our VPP commitments. See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our VPPs.

Gains (Losses) on Sales of Assets

	Years Ended December 31,		
	2018	**2017**	**2016**
		($ in millions)	
Gains (losses) on sales of assets	$ (264)	$ 476	$ 626

In 2018, we sold all of our net acres in the Utica Shale operating area located in Ohio along with related property and equipment (collectively, the “Designated Properties”) for net proceeds of $1.868 billion to Encino and recognized a loss of $273 million associated with the transaction. Also in 2018, 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. We recognized a gain of approximately $12 million associated with the transactions.

In 2017, 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, and recorded a gain of approximately $326 million.

In 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and received from the buyer aggregate net proceeds of approximately $218 million and recorded a gain of approximately $192 million. We also sold the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia, Kentucky and Virginia for proceeds of $140 million. In connection with this divestiture, we purchased the underlying interests in one of our remaining VPP transactions. Inclusive of the VPP gain of $239 million, we recognized a gain of approximately $47 million associated with the transaction. Additionally, we sold certain of our other noncore oil and natural gas properties for net proceeds of approximately $1.048 billion, after post-closing adjustments. In conjunction with certain of these sales, we purchased oil and natural gas interests previously sold to third parties in connection with four of our VPP transactions. The asset divestitures cover various operating areas. Inclusive of the VPP gain of $175 million, we recognized a gain of approximately $351 million associated with the transactions.

See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of these transactions.

Oil, Natural Gas and NGL Production Expenses

	Years Ended December 31,				
	2018	change	2017	change	2016
			($ in millions)		
Oil, natural gas and NGL production expenses					
Marcellus	$ 34	21 %	$ 28	— %	$ 28
Haynesville	57	8 %	53	33 %	40
Eagle Ford	183	(3)%	188	27 %	148
Powder River Basin	49	63 %	30	36 %	22
Mid-Continent	102	(8)%	111	21 %	92
Retained Assets[(a)]	425	4 %	410	24 %	330
Divested Assets	49	(54)%	107	(67)%	325
Total	474	(8)%	517	(21)%	655
Ad valorem tax	65	44 %	45	(18)%	55
Total oil, natural gas and NGL production expenses	$ 539	(4)%	$ 562	(21)%	$ 710
			($ per boe)		
Oil, natural gas and NGL production expenses					
Marcellus	$ 0.68	17 %	$ 0.58	(8)%	$ 0.63
Haynesville	$ 1.20	9 %	$ 1.10	13 %	$ 0.97
Eagle Ford	$ 4.88	(5)%	$ 5.15	23 %	$ 4.18
Powder River Basin	$ 5.36	(3)%	$ 5.53	34 %	$ 4.14
Mid-Continent	$ 11.26	(7)%	$ 12.12	(30)%	$ 17.31
Retained Assets[(a)]	$ 2.76	(1)%	$ 2.78	11 %	$ 2.50
Divested Assets	$ 1.34	(34)%	$ 2.04	(37)%	$ 3.23
Total	$ 2.50	(3)%	$ 2.59	(8)%	$ 2.81
Ad valorem tax	$ 0.34	55 %	$ 0.22	(8)%	$ 0.24
Total oil, natural gas and NGL production expenses per boe	$ 2.84	1 %	$ 2.81	(8)%	$ 3.05

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

2018 vs. 2017. The absolute increase for retained properties was the result of increased production volumes related to our retained assets primarily in the Powder River Basin. The total per unit increase was the result of increased ad valorem tax primarily due to higher prices received for our oil, natural gas and NGL production. Production expenses in 2018 included approximately $15 million associated with VPP production volumes.

2017 vs. 2016. The absolute and per unit decrease was the result of the sale of certain oil and natural gas properties in 2016, partially offset by increased workover costs in the Eagle Ford and increased water disposal costs in the Eagle Ford and Mid-Continent. Production expenses in 2017 and 2016 included approximately $19 million and $44 million, respectively, associated with VPP production volumes.

We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our remaining VPP agreement decrease and operating efficiencies generally improve.

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

	Years Ended December 31,		
	2018	2017	2016
	($ in millions, except per unit)		
Oil, natural gas and NGL gathering, processing and transportation expenses	$ 1,398	$ 1,471	$ 1,855
Oil ($ per bbl)	$ 4.30	$ 3.94	$ 3.61
Natural gas ($ per mcf)	$ 1.32	$ 1.34	$ 1.47
NGL ($ per bbl)	$ 8.37	$ 7.88	$ 7.83
Total ($ per boe)	$ 7.35	$ 7.36	$ 7.98

2018 vs. 2017. The absolute and per unit decrease for oil and natural gas 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 2017 and 2018 divestitures.

2017 vs. 2016. The absolute decrease was primarily due to lower volumes. The per unit decrease was due to contract improvements and asset sales.

Production Taxes

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions, except per unit)				
Production taxes	$ 124	39%	$ 89	20%	$ 74
Production taxes per boe	$ 0.65	48%	$ 0.44	38%	$ 0.32

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

Exploration Expenses

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions, except per unit)				
Impairments of unproved properties	$ 59	(72)%	$ 214	(85)%	$ 1,387
Dry hole expense	37	— %	—	— %	—
Geological and geophysical expense and other	66	214 %	21	(69)%	68
Exploration expense	$ 162	(31)%	$ 235	(84)%	$ 1,455

2018 vs. 2017. The absolute decrease in exploration expense was primarily due to fewer impairments of unproved properties recognized in most of our operating areas.

2017 vs. 2016. The absolute decrease in exploration expense was primarily due to unproved property impairments in our Haynesville and Barnett assets in 2016 with fewer impairments to unproved properties in 2017.

General and Administrative Expenses

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions, except per unit)				
Gross overhead	$ 714	(10)%	$ 791	(12)%	$ 900
Allocated to production expenses	(141)	(20)%	(177)	(15)%	(209)
Allocated to marketing expenses	(20)	(31)%	(29)	(47)%	(55)
Allocated to exploration expenses	(10)	67 %	(6)	200 %	(2)
Capitalized general and administrative expenses	(54)	(10)%	(60)	(8)%	(65)
Reimbursed from third parties	(154)	(17)%	(186)	(25)%	(247)
General and administrative expenses, net	$ 335	1 %	$ 333	3 %	$ 322
General and administrative expenses, net per boe	$ 1.76	5 %	$ 1.67	21 %	$ 1.38

2018 vs. 2017. Gross overhead decreased primarily due to our reduction in workforce. 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 lower producing overhead reimbursements from third party working interest owners, due to certain divestitures in 2017 and 2018.

2017 vs. 2016. Gross overhead decreased primarily due to lower compensation costs and lower legal fees. 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 2016 and 2017.

Restructuring and Other Termination Costs. On January 30, 2018, we underwent a reduction in workforce impacting approximately 13% of employees across all functions, primarily on our Oklahoma City campus. In connection with the reduction, we incurred a total charge of approximately $38 million in 2018 for one-time termination benefits. The charge consisted of $33 million in salary and severance expense and $5 million in other termination benefits. In 2016, we recognized $6 million of charges related to a reduction of workforce in connection with the restructuring of our compressor manufacturing subsidiary and the reductions of workforce resulting from the conveyance of our interests in the Barnett Shale and Devonian Shale operating areas. See Note 21 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our restructuring and termination costs.

Provision for Legal Contingencies, Net

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Provision for legal contingencies, net	$ 26	$ (38)	$ 123

The 2018 and 2016 amounts consist of accruals for loss contingencies primarily related to royalty claims. The 2017 amount consists of the recovery of a legal settlement, partially offset by accruals for loss contingencies primarily related to royalty claims. See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of royalty claims.

Depreciation, Depletion and Amortization

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions, except per unit)				
Depreciation, depletion and amortization	$ 1,737	2%	$ 1,697	— %	$ 1,698
Depreciation, depletion and amortization per boe	$ 9.13	8%	$ 8.49	16 %	$ 7.30

2018 vs. 2017. The absolute and per unit increase in 2018 is primarily the result of a higher depletion rate per boe. 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 due to an updated development plan aligning up-spacing, our activity schedule and well performance.

2017 vs. 2016. The per unit increase was primarily the result of increased production in assets retained, which resulted in a nominal change in the absolute amount when considering the sale of Barnett and certain Mid-Continent assets in 2016 and the sale of certain Haynesville assets in 2017

Impairments

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Impairments due to lower forecasted commodity prices	$ 23	$ 27	$ 73
Impairments due to reduction in future development[(a)]	—	560	—
Impairments due to anticipated sale	55	222	29
Total impairments of oil and natural gas properties	78	809	102
Impairments of other fixed assets	53	5	461
Total impairments	$ 131	$ 814	$ 563

(a) The impairment was the result of an updated development plan in 2017, which included a removal of PUDs from properties in the process of being divested in the Mid-Continent operating area.

Other fixed assets. In 2018, we recorded a $45 million impairment related to 890 compressors and $8 million for other property and equipment for the difference between the fair value and carrying value. In 2016, we recognized impairments totaling $426 million related to other fixed assets sold in our Barnett Shale and Devonian Shale divestitures. See Note 19 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairments.

Other Operating Expense

	Years Ended December 31,				
	2018	change	2017	change	2016
	($ in millions)				
Other operating expense	$ —	(100)%	$ 416	10%	$ 377

The 2017 and 2016 amounts consist of discrete costs incurred to terminate various gathering and transportation agreements, including those associated with oil and natural gas asset divestitures. See Note 20 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our other operating expense.

Interest Expense

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Interest expense on senior notes	$ 591	$ 551	$ 588
Interest expense on term loan	86	127	46
Amortization of loan discount, issuance costs and other	24	40	33
Amortization of premium	(88)	(138)	(165)
Interest expense on revolving credit facility	37	39	35
Realized gains on interest rate derivatives	(3)	(3)	(11)
Unrealized losses on interest rate derivatives	2	4	21
Capitalized interest	(16)	(19)	(19)
Total interest expense	$ 633	$ 601	$ 528
Interest expense per boe[(a)]	$ 3.33	$ 3.01	$ 2.27
Average senior notes borrowings	$ 8,160	$ 7,714	$ 8,749
Average credit facilities borrowings	$ 505	$ 443	$ 195
Average term loan borrowings	$ 911	$ 1,446	$ 537

(a) 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.

See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our debt instruments.

Gains (Losses) on Investments. In 2018, 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. In 2016, we recognized an other-than-temporary impairment of our Sundrop Fuels Inc. (Sundrop) investment of $119 million. See Note 18 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

Gains (Losses) on Purchases or Exchanges of Debt. In 2018, we used the net proceeds from the issuance of our 2024 and 2026 senior notes, together with cash on hand and borrowings under the Chesapeake revolving credit facility, to repay in full $1.233 billion of borrowings under our secured term loan due 2021 for $1.285 billion, which included a $52 million make-whole premium. We recorded a loss of approximately $65 million associated with the repayment of the term loan, including the make-whole premium and the write-off of $13 million of associated deferred charges. Also in 2018, we used the proceeds from the sale of our Utica assets in Ohio to redeem all of the $1.416 billion aggregate principal amount outstanding of our 8.00% Senior Secured Second Lien Notes due 2022 which included a $60 million call premium. We recorded a gain of approximately $331 million associated with the redemption, including the realization of the remaining $391 million difference in principal and book value due to troubled debt restructuring accounting in 2015, offset by the make-whole premium of $60 million. Additionally, we recorded a loss of $3 million associated with certain deferred charges related to the Chesapeake revolving credit facility prior to its amendment and restatement.

In 2017, we retired $2.389 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, redemptions or repayment upon maturity for $2.592 billion, which included the maturity of our 6.25% Euro-denominated Senior Notes due 2017 and the corresponding cross currency swap. We recorded an aggregate gain of approximately $233 million associated with the repurchases and tender offers.

In 2016, we used the proceeds from our term loan facility, convertible notes issuance and senior notes issuance, together with cash on hand, to purchase and retire $2.884 billion principal amount of our outstanding senior notes and contingent convertible senior notes through purchases in the open market, tender offers or repayment upon maturity for $2.734 billion. Additionally, we privately negotiated an exchange of approximately $577 million principal amount of our outstanding senior notes and contingent convertible senior notes for 109,351,707 common shares. We recorded an aggregate gain of approximately $236 million associated with the repurchases and exchanges.

Other Income. In 2018, 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 consolidated statement of operations. See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of this transaction.

Income Tax Expense (Benefit). We recorded an income tax benefit of $10 million in 2018, income tax expense of $2 million in 2017 and an income tax benefit of $190 million in 2016. Our effective tax rate can fluctuate as a result of the impact of various items, including state income taxes, permanent differences, tax law changes and adjustments to the valuation allowance. See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of income tax expense (benefit).

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions we consider to be most significant to our financial statements are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

Oil and Natural Gas Reserves. Estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in oil, natural gas or NGL prices could result in actual results differing significantly from our estimates. See *Supplemental Disclosures About Oil, Natural Gas, and NGL Producing Activities* included in Item 8 of this report for further information.

Oil and Natural Gas Exploration Costs. We follow the successful efforts method of accounting for our oil and natural gas exploration activities. Exploratory drilling costs are initially capitalized, or suspended, pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. Costs of unsuccessful wells are charged to exploration expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. If we determine that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. We review the status of all suspended exploratory drilling costs quarterly. See *Oil and Natural Gas Properties* in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further information on the successful efforts method of accounting.

Impairments. Long-lived assets used in operations, including proved oil and gas properties, are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If there is an indication the carrying amount of an asset may not be recovered, the asset is assessed by management through an established process in which changes to significant assumptions such as prices, volumes, and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is assessed by management using the income approach. Level 3 inputs associated with the calculation of discounted cash flows used in the impairment analysis include our estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves and other relevant data. Additionally, we utilize a combination of NYMEX strip pricing and consensus pricing, adjusted for differentials, to value the reserves.

Derivatives. We use commodity price and financial risk management instruments to mitigate a portion of our exposure to price fluctuations in oil, natural gas and NGL prices. Results of commodity derivative contracts are reflected in oil, natural gas and NGL revenues and results of interest rate derivative contracts are reflected in interest expense.

Due to the volatility of oil, natural gas and NGL prices and, to a lesser extent, interest rates and foreign exchange rates, our financial condition and results of operations may be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2018 and 2017, the fair values of our derivatives were net assets of $282 million and net liabilities of $35 million, respectively.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established 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. 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. Additionally, in accordance with accounting guidance for derivatives and hedging, to the extent that a legal right of set-off exists, we net the value of our derivative instruments with the same counterparty in the accompanying consolidated balance sheets.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the derivative instruments and the transactions being hedged, both at inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our derivative instruments are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Income Taxes. The amount of income taxes recorded requires interpretations and application of complex rules and regulations pertaining to federal, state and local taxing jurisdictions. Income taxes are accounted for using the asset and liability method as required by GAAP. We recognize deferred tax assets and liabilities for temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets for NOL and tax credit carryforwards have also been recognized. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that all or some portion of the deferred tax assets will not be realized. In assessing the need for additional valuation allowances or adjustments to existing valuation allowances, we consider the weight of all available evidence, both positive and negative, concerning the realization of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years;
- reversal of existing deferred tax liabilities against deferred tax assets and whether the carryforward period is so brief that it would limit realization of the tax benefit;
- future sales and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

Our judgments and assumptions in estimating future taxable income include such factors as future operating conditions and commodity prices when determining if deferred tax assets are not more likely than not to be realized. As of December 31, 2018 and 2017, we had deferred tax assets totaling $3.231 billion and $2.805 billion upon which we had a valuation allowance of $2.011 billion and $2.119 billion, respectively.

We also routinely assess potential uncertain tax positions and, if required, establish accruals for such positions. Accounting guidance for recognizing and measuring uncertain tax positions requires that a more likely than not threshold condition be met on a tax position, based solely on its technical merits of being sustained, before any benefit of the uncertain tax position can be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. If a tax position does not meet or exceed the more likely than not threshold then no benefit can be recorded. We accrue any applicable interest related to uncertain tax positions as a component of interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expense. Additional information about uncertain tax positions appears in Note 9 of the notes to our consolidated financial statements included in Item 8 of this report.

Disclosures About Effects of Transactions with Related Parties

Our equity method investees are considered related parties. See Note 10 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of transactions with our equity method investees.

ITEM 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION

Supplementary Information:

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Chesapeake Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Chesapeake Energy Corporation and its subsidiaries (the “Company”) as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), cash flows and stockholders’ equity for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Notes 1 and 2 to the consolidated financial statements, the Company changed the manner in which it accounts for oil and natural gas exploration and development activities in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting (not presented herein) appearing under Item 9A of the Company’s 2018 Annual Report on Form 10-K. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma

February 27, 2019, except with respect to our opinion on the consolidated financial statements insofar as it relates to the change in the manner in which the Company accounts for oil and natural gas exploration and development activities discussed in Notes 1 and 2, as to which the date is May 9, 2019

We have served as the Company's auditor since 1992.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2018	2017
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $2 attributable to our VIE)	$ 4	$ 5
Accounts receivable, net	1,247	1,322
Short-term derivative assets	209	27
Other current assets	138	172
Total Current Assets	1,598	1,526
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on successful efforts accounting:		
Proved oil and natural gas properties ($755 and $755 attributable to our VIE)	25,407	27,932
Unproved properties	1,561	2,024
Other property and equipment	1,721	1,986
Total Property and Equipment, at Cost	28,689	31,942
Less: accumulated depreciation, depletion and amortization (($707) and ($700) attributable to our VIE)	(17,886)	(18,907)
Property and equipment held for sale, net	15	144
Total Property and Equipment, Net	10,818	13,179
LONG-TERM ASSETS:		
Long-term derivative assets	76	—
Other long-term assets	243	220
TOTAL ASSETS	$ 12,735	$ 14,925

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

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

	December 31,	
	2018	2017
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 763	$ 654
Current maturities of long-term debt, net	381	52
Accrued interest	141	137
Short-term derivative liabilities	3	58
Other current liabilities ($2 and $3 attributable to our VIE)	1,599	1,518
Total Current Liabilities	2,887	2,419
LONG-TERM LIABILITIES:		
Long-term debt, net	7,341	9,921
Long-term derivative liabilities	—	4
Asset retirement obligations, net of current portion	155	162
Other long-term liabilities	219	476
Total Long-Term Liabilities	7,715	10,563
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 5,603,458 shares outstanding	1,671	1,671
Common stock, $0.01 par value, 2,000,000,000 shares authorized: 913,715,512 and 908,732,809 shares issued	9	9
Additional paid-in capital	14,378	14,437
Accumulated deficit	(13,912)	(14,130)
Accumulated other comprehensive loss	(23)	(57)
Less: treasury stock, at cost; 3,246,553 and 2,240,394 common shares	(31)	(31)
Total Chesapeake Stockholders' Equity	2,092	1,899
Noncontrolling interests	41	44
Total Equity	2,133	1,943
TOTAL LIABILITIES AND EQUITY	$ 12,735	$ 14,925

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2018	2017	2016
	($ in millions except per share data)		
REVENUES AND OTHER:			
Oil, natural gas and NGL	$ 5,155	$ 4,985	$ 3,288
Marketing	5,076	4,511	4,584
Total Revenues	10,231	9,496	7,872
Other	63	67	207
Gains (losses) on sales of assets	(264)	476	626
Total Revenues and Other	10,030	10,039	8,705
OPERATING EXPENSES:			
Oil, natural gas and NGL production	539	562	710
Oil, natural gas and NGL gathering, processing and transportation	1,398	1,471	1,855
Production taxes	124	89	74
Exploration	162	235	1,455
Marketing	5,158	4,598	4,778
General and administrative	335	333	322
Restructuring and other termination costs	38	—	6
Provision for legal contingencies, net	26	(38)	123
Depreciation, depletion and amortization	1,737	1,697	1,698
Impairments	131	814	563
Other operating expenses	—	416	377
Total Operating Expenses	9,648	10,177	11,961
INCOME (LOSS) FROM OPERATIONS	382	(138)	(3,256)
OTHER INCOME (EXPENSE):			
Interest expense	(633)	(601)	(528)
Gains (losses) on investments	139	—	(137)
Gains on purchases or exchanges of debt	263	233	236
Other income	67	6	5
Total Other Expense	(164)	(362)	(424)
INCOME (LOSS) BEFORE INCOME TAXES	218	(500)	(3,680)
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	—	(9)	(19)
Deferred income taxes	(10)	11	(171)
Total Income Tax Expense (Benefit)	(10)	2	(190)
NET INCOME (LOSS)	228	(502)	(3,490)
Net income attributable to noncontrolling interests	(2)	(3)	(3)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	226	(505)	(3,493)
Preferred stock dividends	(92)	(85)	(97)
Loss on exchange of preferred stock	—	(41)	(428)
Earnings allocated to participating securities	(1)	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 133	$ (631)	$ (4,018)
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ 0.15	$ (0.70)	$ (5.26)
Diluted	$ 0.15	$ (0.70)	$ (5.26)
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	909	906	764
Diluted	909	906	764

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

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

	Years Ended December 31,		
	2018	**2017**	**2016**
	($ in millions)		
NET INCOME (LOSS)	$ 228	$ (502)	$ (3,490)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Unrealized gains (losses) on derivative instruments, net of income tax benefit of $0, $0, and ($14)	—	5	(13)
Reclassification of losses on settled derivative instruments, net of income tax expense of $0, $0 and $18	34	34	16
Other Comprehensive Income	34	39	3
COMPREHENSIVE INCOME (LOSS)	262	(463)	(3,487)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(2)	(3)	(3)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 260	$ (466)	$ (3,490)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ 228	$ (502)	$ (3,490)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	1,737	1,697	1,698
Deferred income tax expense (benefit)	(10)	11	(171)
Derivative (gains) losses, net	26	(409)	739
Cash receipts (payments) on derivative settlements, net	(345)	(18)	448
Stock-based compensation	32	49	52
(Gains) losses on sales of assets	264	(476)	(212)
Impairments	131	814	563
Exploratory dry hole expense and leasehold impairments	96	214	1,387
(Gains) losses on investments	(139)	—	137
Gains on purchases or exchanges of debt	(263)	(235)	(236)
Other	(118)	(132)	(127)
(Increase) decrease in accounts receivable and other assets	16	(163)	(4)
(Decrease) increase in accounts payable, accrued liabilities and other	75	(375)	(1,764)
Net Cash Provided By (Used In) Operating Activities	1,730	475	(980)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(1,848)	(2,113)	(1,192)
Acquisitions of proved and unproved properties	(128)	(88)	(115)
Proceeds from divestitures of proved and unproved properties	2,231	1,249	1,406
Additions to other property and equipment	(21)	(21)	(37)
Proceeds from sales of other property and equipment	147	55	131
Proceeds from sales of investments	74	—	—
Other	—	—	(77)
Net Cash Provided By (Used In) Investing Activities	455	(918)	116

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

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

CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility borrowings	11,697	7,771	5,146
Payments on revolving credit facility borrowings	(12,059)	(6,990)	(5,146)
Proceeds from issuance of senior notes, net	1,236	1,585	2,210
Proceeds from issuance of term loan, net	—	—	1,476
Cash paid to purchase debt	(2,813)	(2,592)	(2,734)
Extinguishment of other financing	(122)	—	—
Cash paid for preferred stock dividends	(92)	(183)	—
Distributions to noncontrolling interest owners	(6)	(8)	(10)
Other	(27)	(17)	(21)
Net Cash Provided By (Used In) Financing Activities	(2,186)	(434)	921
Net increase (decrease) in cash and cash equivalents	(1)	(877)	57
Cash and cash equivalents, beginning of period	5	882	825
Cash and cash equivalents, end of period	$ 4	$ 5	$ 882

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

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest paid, net of capitalized interest	$ 664	$ 667	$ 576
Income taxes paid, net of refunds received	$ (3)	$ (16)	$ (27)
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Change in accrued drilling and completion costs	$ 174	$ 14	$ (23)
Change in accrued acquisitions of proved and unproved properties	$ 7	$ 9	$ (13)
Change in divested proved and unproved properties	$ (21)	$ (57)	$ 52
Acquisition of other property and equipment including assets under capital lease	$ 27	$ —	$ —
Debt exchanged for common stock	$ —	$ —	$ 471

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 1,671	$ 1,771	$ 3,062
Exchange/conversions of 0, 236,048 and 1,412,009 shares of preferred stock for common stock	—	(100)	(1,291)
Balance, end of period	1,671	1,671	1,771
COMMON STOCK:			
Balance, beginning of period	9	9	7
Exchange of senior notes, contingent convertible notes and preferred stock	—	—	1
Conversion of preferred stock	—	—	1
Balance, end of period	9	9	9
ADDITIONAL PAID-IN CAPITAL:			
Balance, beginning of period	14,437	14,486	12,403
Stock-based compensation	33	54	64
Exchange of contingent convertible notes for 0, 0 and 55,427,782 shares of common stock	—	—	241
Exchange of senior notes for 0, 0 and 53,923,925 shares of common stock	—	—	229
Exchange/conversion of preferred stock for 0, 9,965,835, and 120,186,195 shares of common stock	—	100	1,290
Issuance of 5.5% convertible senior notes due 2026	—	—	445
Tax effect on the issuance of 5.5% convertible senior notes due 2026	—	—	(165)
Equity component of contingent convertible notes repurchased, net of tax	—	(20)	(16)
Dividends on preferred stock	(92)	(183)	—
Issuance costs	—	—	(5)
Balance, end of period	14,378	14,437	14,486
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance, beginning of period	(14,130)	(13,625)	(13,084)
Net income (loss) attributable to Chesapeake	226	(505)	(3,493)
Cumulative effect of change in accounting principle	(8)	—	2,952
Balance, end of period	(13,912)	(14,130)	(13,625)
ACCUMULATED OTHER COMPREHENSIVE LOSS:			
Balance, beginning of period	(57)	(96)	(99)
Hedging activity	34	39	3
Balance, end of period	(23)	(57)	(96)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY - (Continued)

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
TREASURY STOCK – COMMON:			
Balance, beginning of period	(31)	(27)	(33)
Purchase of 1,510,022, 1,206,419, and 37,871 shares for company benefit plans	(4)	(7)	—
Release of 503,863, 186,529 and 255,091 shares from company benefit plans	4	3	6
Balance, end of period	(31)	(31)	(27)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	2,092	1,899	2,518
NONCONTROLLING INTERESTS:			
Balance, beginning of period	44	49	141
Net income attributable to noncontrolling interests	2	3	3
Distributions to noncontrolling interest owners	(5)	(8)	(4)
Cumulative effect of change in accounting principle	—	—	(91)
Balance, end of period	41	44	49
TOTAL EQUITY	$ 2,133	$ 1,943	$ 2,567

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake", “we,” “our”, “us” or the "Company") is an oil and natural gas exploration and production company engaged in the acquisition, exploration and development of properties for the production of oil, natural gas and natural gas liquids (NGL) from underground reservoirs. Our operations are located onshore in the United States.

Basis of Presentation

The accompanying consolidated financial statements of Chesapeake were prepared in accordance with GAAP and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated.

Recast Financial Information for Change in Accounting Principle

In the first quarter of 2019, we voluntarily changed our method of accounting for oil and natural gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, financial information for prior periods presented herein has been recast to reflect retrospective application of the successful efforts method. Although the full cost method of accounting for oil and natural gas exploration and development activities continues to be an accepted alternative, the successful efforts method of accounting is the generally preferred method of the SEC and, because it is more widely used in the industry, we expect the change to improve the comparability of our financial statements to our peers. We also believe the successful efforts method provides a more representational depiction of assets and operating results and provides for our investments in oil and natural gas properties to be assessed for impairment in accordance with Accounting Standards Codification (ASC) Topic 360, *Property Plant and Equipment,* rather than valuations based on prices and costs prescribed under the full cost method as of the balance sheet date. For detailed information regarding the effects of the change to the successful efforts method, see Note 2.

Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the related disclosures in the financial statements. Management evaluates its estimates and related assumptions regularly, including those related to the impairment of oil and natural gas properties, oil and natural gas reserves, derivatives, income taxes, unevaluated properties not subject to evaluation, impairment of other property and equipment, environmental remediation costs, asset retirement obligations, litigation and regulatory proceedings and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ significantly from these estimates.

Consolidation

We consolidate entities in which we have a controlling financial interest. We consolidate subsidiaries in which we hold, directly or indirectly, more than 50% of the voting rights and variable interest entities (VIEs) in which we are the primary beneficiary. We consolidate a VIE when we are the primary beneficiary, which is the party that has both (i) the power to direct the activities that most significantly impact the VIE’s economic performance and (ii) through its interests in the VIE, the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether we own a variable interest in a VIE, we perform a qualitative analysis of the entity’s design, organizational structure, primary decision makers and relevant agreements. We continually monitor our consolidated VIE to determine if any events have occurred that could cause the primary beneficiary to change. See Note 11 for further discussion of our VIE. We use the equity method of accounting to record our net interests where we have the ability to exercise significant influence through our investment but lack a controlling financial interest. Under the equity method, our share of net income (loss) is included in our consolidated statements of operations according to our equity ownership or according to the terms of the applicable governing instrument. Undivided interests in oil and natural gas properties are consolidated on a proportionate basis.

Segments

Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating an enterprise's resources and assessing its operating performance. We have concluded that we have only one reportable operating segment, which is exploration and production because our marketing activities are ancillary to our operations.

Noncontrolling Interests

Noncontrolling interests represent third-party equity ownership in certain of our consolidated subsidiaries and are presented as a component of equity. See Note 11 for further discussion of noncontrolling interests.

Cash and Cash Equivalents

For purposes of the consolidated financial statements, we consider investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents.

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. See Note 8 for further discussion of our accounts receivable.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas properties. Under this method, exploration costs such as exploratory geological and geophysical costs, expiration of unproved leasehold, delay rentals and exploration overhead are expensed as incurred. All costs related to production, general corporate overhead and similar activities are also expensed as incurred. All property acquisition costs and development costs are capitalized when incurred.

Exploratory drilling costs are initially capitalized, or suspended, pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. Costs of unsuccessful wells are charged to exploration expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If we determine that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. We review the status of all suspended exploratory drilling costs quarterly. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of oil and natural gas are capitalized.

Costs of drilling and equipping successful wells, costs to construct or acquire facilities, and associated asset retirement costs are depreciated using the unit-of-production (UOP) method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves.

Proceeds from the sales of individual oil and natural gas properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depreciation, depletion and amortization, if doing so does not materially impact the depletion rate of an amortization base. Generally, no gain or loss is recognized until an entire amortization base is sold. However, a gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

When circumstances indicate that the carrying value of proved oil and gas properties may not be recoverable, we compare unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on our estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized costs, the capitalized costs are reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820, *Fair Value Measurements*. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of future production volumes, commodity prices, operating costs, and capital investment plans, considering all available information at the date of review. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a discount rate believed to be consistent with those applied by market participants. We have classified these fair value measurements as Level 3 in the fair value hierarchy.

Other Property and Equipment

Other property and equipment consists primarily of buildings and improvements, land, vehicles, computers, natural gas compressors under capital lease and office equipment. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. Other property and equipment costs, excluding land, are depreciated on a straight-line basis and recorded within depreciation, depletion and amortization in the consolidated statement of operations. Natural gas compressors under capital lease are depreciated over the shorter of their estimated useful lives or the term of the related lease.

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including any disposal value, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets and discounted cash flow.

Capitalized Interest

Interest from external borrowings is capitalized on significant investments in major development projects until the asset is ready for service using the weighted average borrowing rate of outstanding borrowings. Capitalized interest is determined by multiplying our weighted average borrowing cost on debt by the average amount of qualifying costs incurred. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying asset.

Accounts Payable

Included in accounts payable as of December 31, 2018 and 2017 are liabilities of approximately $104 million and $92 million, respectively, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts.

Debt Issuance Costs

Included in other long-term assets are costs associated with the issuance and amendments of the Chesapeake revolving credit facility. The remaining unamortized issuance costs as of December 31, 2018 and 2017, totaled $30 million and $22 million, respectively, and are being amortized over the life of the Chesapeake revolving credit facility using the straight-line method. Included in debt are costs associated with the issuance of our senior notes. The remaining unamortized issuance costs as of December 31, 2018 and 2017, totaled $53 million and $63 million, respectively, and are being amortized over the life of the senior notes using the effective interest method.

Litigation Contingencies

We are subject to litigation and regulatory proceedings, claims and liabilities that arise in the ordinary course of business. We accrue losses associated with litigation and regulatory claims when such losses are probable and reasonably estimable. If we determine that a loss is probable and cannot estimate a specific amount for that loss but can estimate a range of loss, our best estimate within the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred.

Environmental Remediation Costs

We record environmental reserves for estimated remediation costs related to existing conditions from past operations when the responsibility to remediate is probable and the costs can be reasonably estimated. Expenditures that create future benefits or contribute to future revenue generation are capitalized.

Asset Retirement Obligations

We recognize liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our oil and natural gas properties. See Note 23 for further discussion of asset retirement obligations.

Revenue Recognition

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. Prior to the adoption of *Revenue from Contracts with Customers* (Topic 606) on January 1, 2018, revenue from the sale of oil, natural gas and NGL was recognized when title passed 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 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 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 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 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.

Fair Value Measurements

Certain financial instruments are reported on a recurring basis at fair value on our consolidated balance sheets. We also use fair value measurements on a nonrecurring basis when a qualitative assessment of our assets indicates a potential impairment. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (i.e. an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments.

Derivatives

Derivative instruments are recorded at fair value, and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are followed. As of December 31, 2018, none of our open derivative instruments were designated as cash flow hedges.

Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows. All of our derivative instruments are subject to master netting arrangements by contract type which provide for the offsetting of asset and liability positions within each contract type, as well as related cash collateral if applicable, by counterparty. Therefore, we net the value of our derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

We have established the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. 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. Derivative transactions are 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. See Note 14 for further discussion of our derivative instruments.

Share-Based Compensation

Our share-based compensation program consists of restricted stock, stock options, performance share units and cash restricted stock units granted to employees and restricted stock granted to non-employee directors under our Long Term Incentive Plan. We recognize the cost of employee services received in exchange for restricted stock and stock options based on the fair value of the equity instruments as of the grant date. For employees, this value is amortized over the vesting period, which is generally three years from the grant date. For directors, although restricted stock grants vest over three years, this value is recognized immediately as there is a non-substantive service condition for vesting. Because performance share units are settled in cash, they are classified as a liability in our consolidated financial statements and are measured at fair value as of the grant date and re-measured at fair value at the end of each reporting period. These fair value adjustments are recognized as general and administrative expense in the consolidated statements of operations.

To the extent compensation expense relates to employees directly involved in the acquisition of oil and natural gas leasehold and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expense, oil, natural gas and NGL production expense, exploration expense, or marketing expense, based on the employees involved in those activities. See Note 12 for further discussion of share-based compensation.

Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) issued 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. See Note 8 for further details regarding our adoption of Topic 606.

In February 2018, the FASB issued Accounting Standards Update (ASU) 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The new standard allows for stranded tax effects resulting from the tax reform legislation commonly known as the Tax Cuts and Jobs Act, which was signed into law on December 22, 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. This standard is effective for us beginning on January 1, 2019, and we will elect not to reclassify the income tax effects of the Tax Act from accumulated other comprehensive income to retained earnings.

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 plan to adopt this standard on January 1, 2019 and do not expect it to have an impact on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* which requires lessees to recognize a lease liability and a right-of-use (ROU) asset on the balance sheet for all leases, including operating leases, with terms in excess of 12 months. This ASU modifies the definition of a lease and outlines the recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The standard will not apply to our leases of mineral rights to explore for or use oil and natural gas resources, including the intangible rights to explore for those natural resources and rights to use the land in which those natural resources are contained. We plan to make certain elections permitting us to not reassess whether any expired or existing contracts contained leases, permitting us to not reassess the lease classification for any expired or existing leases (all existing leases that were classified as operating leases in accordance with Topic 840 will be classified as operating leases, and all existing leases that were classified as capital leases in accordance with Topic 840 will be classified as finance leases), and permitting us to not reassess initial direct costs for any existing leases. We will also take an election permitting us to continue applying our current policy for land easements that existed as of, or expired before, the effective date and to not recognize a ROU asset or lease liability for short-term leases.

We have completed our assessment of contracts potentially affected by the new standard and have completed our assessment of the accounting treatment for these leases. The adoption will primarily impact other assets and other liabilities and will also impact ongoing disclosures but will not have a material impact on our balance sheet, results of operations or cash flows. We plan to adopt the new standard on January 1, 2019, the effective date, and as permitted by ASU 2018-11 we will not adjust comparative-period financial statements and will continue to apply the guidance in ASC 840, including its disclosure requirements, in the comparative periods presented prior to adoption.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2017 and 2016 to conform to the presentation used for the 2018 consolidated financial statements.

2. Change in Accounting Principle

In the first quarter of 2019, we voluntarily changed our method of accounting for oil and natural gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, financial information for prior periods presented herein has been recast to reflect retrospective application of the successful efforts method. In general, under the successful efforts method, exploration costs such as exploratory dry holes, exploratory geophysical and geological costs, delay rentals, unproved leasehold impairments and exploration overhead are charged against earnings as incurred, versus being capitalized under the full cost method of accounting. The successful efforts method also provides for the assessment of potential property impairments by comparing the net carrying value of oil and natural gas properties to associated projected undiscounted pre-tax future net cash flows. If the expected undiscounted pre-tax future net cash flows are lower than the unamortized capitalized costs, the capitalized costs are reduced to fair value. Under the full cost method of accounting, a write-down would be required if the net carrying value of oil and natural gas properties exceeds a full cost ceiling using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months. In addition, gains or losses, if applicable, are generally recognized on the disposition of oil and natural gas property and equipment under the successful efforts method, as opposed to an adjustment to the net carrying value of the assets remaining under the full cost method. Our consolidated financial statements have been recast to reflect these differences.

	December 31, 2018		
CONSOLIDATED BALANCE SHEETS	**As Previously Reported Under Full Cost**	**Adjustment**	**As Revised Under Successful Efforts**
	($ in millions except per share data)		
Proved oil and natural gas properties ($488 and $755 attributable to our VIE)	$ 69,642	$ (44,235)	$ 25,407
Unproved properties	$ 2,337	$ (776)	$ 1,561
Total Property and Equipment, at Cost	$ 73,700	$ (45,011)	$ 28,689
Less: accumulated depreciation, depletion and amortization (($461) and ($707) attributable to our VIE)	$ (64,685)	$ 46,799	$ (17,886)
Total Property and Equipment, Net	$ 9,030	$ 1,788	$ 10,818
Total Assets	$ 10,947	$ 1,788	$ 12,735
Other current liabilities	$ 1,540	$ 59	$ 1,599
Other long-term liabilities	$ 156	$ 63	$ 219
Total long-term liabilities	$ 7,652	$ 63	$ 7,715
Accumulated deficit	$ (15,660)	$ 1,748	$ (13,912)
Total Chesapeake Stockholders’ Equity	$ 344	$ 1,748	$ 2,092
Noncontrolling interests	$ 123	$ (82)	$ 41
Total Equity	$ 467	$ 1,666	$ 2,133
Total Liabilities and Equity	$ 10,947	$ 1,788	$ 12,735

	December 31, 2017		
CONSOLIDATED BALANCE SHEETS	**As Previously Reported Under Full Cost**	**Adjustment**	**As Revised Under Successful Efforts**
	($ in millions except per share data)		
Other current assets	$ 171	$ 1	$ 172
Proved oil and natural gas properties ($488 and $755 attributable to our VIE)	$ 68,858	$ (40,926)	$ 27,932
Unproved properties	$ 3,484	$ (1,460)	$ 2,024
Total Property and Equipment, at Cost	$ 74,328	$ (42,386)	$ 31,942
Less: accumulated depreciation, depletion and amortization (($461) and ($700) attributable to our VIE)	$ (63,664)	$ 44,757	$ (18,907)
Property and equipment held for sale, net	$ 16	$ 128	$ 144
Total Property and Equipment, Net	$ 10,680	$ 2,499	$ 13,179
Total Assets	$ 12,425	$ 2,500	$ 14,925
Other current liabilities	$ 1,455	$ 63	$ 1,518
Other long-term liabilities	$ 354	$ 122	$ 476
Total long-term liabilities	$ 10,441	$ 122	$ 10,563
Accumulated deficit	$ (16,525)	$ 2,395	$ (14,130)
Total Chesapeake Stockholders’ Equity (Deficit)	$ (496)	$ 2,395	$ 1,899
Noncontrolling interests	$ 124	$ (80)	$ 44
Total Equity (Deficit)	$ (372)	$ 2,315	$ 1,943
Total Liabilities and Equity	$ 12,425	$ 2,500	$ 14,925

CONSOLIDATED STATEMENTS OF OPERATIONS	Year Ended December 31, 2018		
	As Previously Reported Under Full Cost	Adjustment	As Revised Under Successful Efforts
	($ in millions except per share data)		
Other revenues	$ —	$ 63	$ 63
Loss on sale of assets	$ —	$ (264)	$ (264)
Total revenues	$ 10,231	$ (201)	$ 10,030
Exploration expense	$ —	$ 162	$ 162
General and administrative	$ 280	$ 55	$ 335
Depreciation, depletion and amortization	$ 1,145	$ 592	$ 1,737
Loss on sale of oil and natural gas properties	$ 578	$ (578)	$ —
Impairments	$ 53	$ 78	$ 131
Other operating expenses	$ 10	$ (10)	$ —
Total operating expenses	$ 9,349	$ 299	$ 9,648
Income (loss) from operations	$ 882	$ (500)	$ 382
Interest expense	$ (487)	$ (146)	$ (633)
Other income	$ 70	$ (3)	$ 67
Total other expense	$ (15)	$ (149)	$ (164)
Income (loss) before income taxes	$ 867	$ (649)	$ 218
Net income (loss)	$ 877	$ (649)	$ 228
Net (income) loss attributable to noncontrolling interest	$ (4)	$ 2	$ (2)
Net income (loss) attributable to Chesapeake	$ 873	$ (647)	$ 226
Earnings allocated to participating securities	$ (6)	$ 5	$ (1)
Net income (loss) available to common stockholders	$ 775	$ (642)	$ 133
Earnings (loss) per common share basic	$ 0.85	$ (0.70)	$ 0.15
Earnings (loss) per common share diluted	$ 0.85	$ (0.70)	$ 0.15

	Year Ended December 31, 2017		
CONSOLIDATED STATEMENTS OF OPERATIONS	**As Previously Reported Under Full Cost**	**Adjustment**	**As Revised Under Successful Efforts**
	($ in millions except per share data)		
Other revenues	$ —	$ 67	$ 67
Gain on sales of assets	$ —	$ 476	$ 476
Total revenues	$ 9,496	$ 543	$ 10,039
Exploration expense	$ —	$ 235	$ 235
General and administrative	$ 262	$ 71	$ 333
Depreciation, depletion and amortization	$ 995	$ 702	$ 1,697
Impairments	$ 5	$ 809	$ 814
Other operating expenses	$ 413	$ 3	$ 416
Total operating expenses	$ 8,357	$ 1,820	$ 10,177
Income (loss) from operations	$ 1,139	$ (1,277)	$ (138)
Interest expense	$ (426)	$ (175)	$ (601)
Other income	$ 9	$ (3)	$ 6
Total other expense	$ (184)	$ (178)	$ (362)
Income (loss) before income taxes	$ 955	$ (1,455)	$ (500)
Net income (loss)	$ 953	$ (1,455)	$ (502)
Net (income) loss attributable to noncontrolling interest	$ (4)	$ 1	$ (3)
Net income (loss) attributable to Chesapeake	$ 949	$ (1,454)	$ (505)
Earnings allocated to participating securities	$ (10)	$ 10	$ —
Net income (loss) available to common stockholders	$ 813	$ (1,444)	$ (631)
Earnings (loss) per common share basic	$ 0.90	$ (1.60)	$ (0.70)
Earnings (loss) per common share diluted	$ 0.90	$ (1.60)	$ (0.70)

CONSOLIDATED STATEMENTS OF OPERATIONS	Year Ended December 31, 2016		
	As Previously Reported Under Full Cost	Adjustment	As Revised Under Successful Efforts
	($ in millions except per share data)		
Other revenues	$ —	$ 207	$ 207
Gain on sales of assets	$ —	$ 626	$ 626
Total revenues	$ 7,872	$ 833	$ 8,705
Exploration expense	$ —	$ 1,455	$ 1,455
General and administrative	$ 240	$ 82	$ 322
Depreciation, depletion and amortization	$ 1,107	$ 591	$ 1,698
Impairments	$ 3,025	$ (2,462)	$ 563
Other operating expenses	$ 365	$ 12	$ 377
Total operating expenses	$ 12,283	$ (322)	$ 11,961
Income (loss) from operations	$ (4,411)	$ 1,155	$ (3,256)
Interest expense	$ (296)	$ (232)	$ (528)
Other income	$ 19	$ (14)	$ 5
Total other expense	$ (178)	$ (246)	$ (424)
Income (loss) before income taxes	$ (4,589)	$ 909	$ (3,680)
Net income (loss)	$ (4,399)	$ 909	$ (3,490)
Net (income) loss attributable to noncontrolling interest	$ 9	$ (12)	$ (3)
Net income (loss) attributable to Chesapeake	$ (4,390)	$ 897	$ (3,493)
Net income (loss) available to common stockholders	$ (4,915)	$ 897	$ (4,018)
Earnings (loss) per common share basic	$ (6.43)	$ 1.17	$ (5.26)
Earnings (loss) per common share diluted	$ (6.43)	$ 1.17	$ (5.26)

	Year Ended December 31, 2018		
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	**As Previously Reported Under Full Cost**	**Adjustment**	**As Revised Under Successful Efforts**
	($ in millions except per share data)		
Net income (loss)	$ 877	$ (649)	$ 228
Comprehensive income (loss)	$ 911	$ (649)	$ 262
Comprehensive (income) loss attributable to noncontrolling interests	$ (4)	$ 2	$ (2)
Comprehensive income (loss) attributable to Chesapeake	$ 907	$ (647)	$ 260

	Year Ended December 31, 2017		
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	**As Previously Reported Under Full Cost**	**Adjustment**	**As Revised Under Successful Efforts**
	($ in millions except per share data)		
Net income (loss)	$ 953	$ (1,455)	$ (502)
Comprehensive income (loss)	$ 992	$ (1,455)	$ (463)
Comprehensive (income) loss attributable to noncontrolling interests	$ (4)	$ 1	$ (3)
Comprehensive income (loss) attributable to Chesapeake	$ 988	$ (1,454)	$ (466)

	Year Ended December 31, 2016		
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	**As Previously Reported Under Full Cost**	**Adjustment**	**As Revised Under Successful Efforts**
	($ in millions except per share data)		
Net income (loss)	$ (4,399)	$ 909	$ (3,490)
Comprehensive income (loss)	$ (4,396)	$ 909	$ (3,487)
Comprehensive (income) loss attributable to noncontrolling interests	$ 9	$ (12)	$ (3)
Comprehensive income (loss) attributable to Chesapeake	$ (4,387)	$ 897	$ (3,490)

	Year Ended December 31, 2018					
CONSOLIDATED STATEMENTS OF CASH FLOWS	**As Previously Reported Under Full Cost**		**Adjustment**		**As Revised Under Successful Efforts**	
	($ in millions except per share data)					
Net income	$	877	$	(649)	$	228
Depreciation, depletion and amortization	$	1,145	$	592	$	1,737
Loss on sale of oil and gas properties	$	578	$	(578)	$	—
Losses on sales of assets	$	—	$	264	$	264
Impairments	$	53	$	78	$	131
Exploratory dry hole expense and leasehold impairments	$	—	$	96	$	96
Other	$	(108)	$	(10)	$	(118)
Increase in accounts payable, accrued liabilities and other	$	138	$	(63)	$	75
Net cash provided by operating activities	$	2,000	$	(270)	$	1,730
Drilling and completion costs	$	(1,958)	$	110	$	(1,848)
Acquisition of proved and unproved properties	$	(288)	$	160	$	(128)
Net cash provided by investing activities	$	185	$	270	$	455

	Year Ended December 31, 2017					
CONSOLIDATED STATEMENTS OF CASH FLOWS	**As Previously Reported Under Full Cost**		**Adjustment**		**As Revised Under Successful Efforts**	
	($ in millions except per share data)					
Net income (loss)	$	953	$	(1,455)	$	(502)
Depreciation, depletion and amortization	$	995	$	702	$	1,697
Gains on sales of assets	$	—	$	(476)	$	(476)
Impairments	$	5	$	809	$	814
Exploratory dry hole expense and leasehold impairments	$	—	$	214	$	214
Other	$	(135)	$	3	$	(132)
Decrease in accounts payable, accrued liabilities and other	$	(308)	$	(67)	$	(375)
Net cash provided by operating activities	$	745	$	(270)	$	475
Drilling and completion costs	$	(2,186)	$	73	$	(2,113)
Acquisition of proved and unproved properties	$	(285)	$	197	$	(88)
Net cash used in investing activities	$	(1,188)	$	270	$	(918)

	Year Ended December 31, 2016		
CONSOLIDATED STATEMENTS OF CASH FLOWS	**As Previously Reported Under Full Cost**	**Adjustment**	**As Revised Under Successful Efforts**
	($ in millions except per share data)		
Net loss	$ (4,399)	$ 909	$ (3,490)
Depreciation, depletion and amortization	$ 1,107	$ 591	$ 1,698
Gain on sales of assets	$ —	$ (212)	$ (212)
Impairments	$ 3,025	$ (2,462)	$ 563
Exploratory dry hole expense and leasehold impairments	$ —	$ 1,387	$ 1,387
Other	$ (145)	$ 18	$ (127)
Decrease in accounts payable, accrued liabilities and other	$ (757)	$ (1,007)	$ (1,764)
Net cash used in operating activities	$ (204)	$ (776)	$ (980)
Drilling and completion costs	$ (1,295)	$ 103	$ (1,192)
Acquisition of proved and unproved properties	$ (788)	$ 673	$ (115)
Net cash provided by (used in) investing activities	$ (660)	$ 776	$ 116

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	Year Ended December 31, 2018		
	As Previously Reported Under Full Cost	Adjustment	As Revised Under Successful Efforts
	($ in millions except per share data)		
Accumulated deficit, beginning of period	$ (16,525)	$ 2,395	$ (14,130)
Net income attributable to Chesapeake	$ 873	$ (647)	$ 226
Accumulated deficit, end of period	$ (15,660)	$ 1,748	$ (13,912)
Total Chesapeake stockholders' equity (deficit)	$ 344	$ 1,748	$ 2,092
Noncontrolling interests, beginning of period	$ 124	$ (80)	$ 44
Net income (loss) attributable to noncontrolling interests	$ 4	$ (2)	$ 2
Noncontrolling interests, end of period	$ 123	$ (82)	$ 41
Total equity (deficit)	$ 467	$ 1,666	$ 2,133

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	Year Ended December 31, 2017		
	As Previously Reported Under Full Cost	Adjustment	As Revised Under Successful Efforts
	($ in millions except per share data)		
Accumulated deficit, beginning of period	$ (17,474)	$ 3,849	$ (13,625)
Net income attributable to Chesapeake	$ 949	$ (1,454)	$ (505)
Accumulated deficit, end of period	$ (16,525)	$ 2,395	$ (14,130)
Total Chesapeake stockholders' equity (deficit)	$ (496)	$ 2,395	$ 1,899
Noncontrolling interests, beginning of period	$ 128	$ (79)	$ 49
Net income (loss) attributable to noncontrolling interests	$ 4	$ (1)	$ 3
Noncontrolling interests, end of period	$ 124	$ (80)	$ 44
Total equity (deficit)	$ (372)	$ 2,315	$ 1,943

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	Year Ended December 31, 2016		
	As Previously Reported Under Full Cost	Adjustment	As Revised Under Successful Efforts
	($ in millions except per share data)		
Net income attributable to Chesapeake	$ (4,390)	$ 897	$ (3,493)
Cumulative effect of change in accounting principle	$ —	$ 2,952	$ 2,952
Accumulated deficit, end of period	$ (17,474)	$ 3,849	$ (13,625)
Total Chesapeake stockholders' equity (deficit)	$ (1,331)	$ 3,849	$ 2,518
Noncontrolling interests, beginning of period	$ 141	$ —	$ 141
Net income (loss) attributable to noncontrolling interests	$ (9)	$ 12	$ 3
Cumulative effect of change in accounting principle	$ —	$ (91)	$ (91)
Noncontrolling interests, end of period	$ 128	$ (79)	$ 49
Total equity (deficit)	$ (1,203)	$ 3,770	$ 2,567

3. Earnings Per Share

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

Diluted EPS is calculated assuming the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For 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 4 for further discussion of our convertible senior notes and contingent convertible senior notes.

Shares of common stock for the following dilutive securities were excluded from the calculation of diluted EPS as the effect was antidilutive.

	Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Common stock equivalent of our preferred stock outstanding	60	60	63
Common stock equivalent of our convertible senior notes outstanding	146	146	146
Common stock equivalent of our preferred stock outstanding prior to exchange	—	1	37
Participating securities	1	1	1

4. Debt

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

	December 31, 2018		December 31, 2017	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
7.25% senior notes due 2018	—	—	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[(a)]	—	—	1,416	1,895
5.75% senior notes due 2023	338	338	338	338
7.00% senior notes due 2024	850	850	—	—
8.00% senior notes due 2025	1,300	1,291	1,300	1,290
5.5% convertible senior notes due 2026[(b)(c)(d)]	1,250	866	1,250	837
7.5% senior notes due 2026	400	400	—	—
8.00% senior notes due 2027	1,300	1,299	1,300	1,298
2.25% contingent convertible senior notes due 2038[(b)(d)]	1	1	9	8
Term loan due 2021	—	—	1,233	1,233
Revolving credit facility	419	419	781	781
Debt issuance costs	—	(53)	—	(63)
Interest rate derivatives	—	1	—	2
Total debt, net	8,168	7,722	9,981	9,973
Less current maturities of long-term debt, net[(e)]	(381)	(381)	(53)	(52)
Total long-term debt, net	$ 7,787	$ 7,341	$ 9,928	$ 9,921

(a) The carrying amount as of December 31, 2017 included a premium amount of $479 million associated with a troubled debt restructuring. The premium was being amortized based on the effective yield method.

(b) 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.

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

Optional Conversion by Holders. Prior to maturity under certain circumstances and at the holder’s option, the notes are convertible. The notes may be converted into cash, our common stock, or a combination of cash and common stock, at our election. One triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. During the fourth quarter of 2018, the price of our common stock was below the threshold level and, as a result, the holders do not have the option to convert their notes in the first quarter of 2019 under this provision. The notes are also convertible, at the holder’s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision during the year ended December 31, 2018. Upon conversion of a convertible senior note, the holder will receive cash, common stock or a combination of cash and common stock, at our election, according to the conversion rate specified in the indenture.

The common stock price conversion threshold amount for the convertible senior notes is 130% of the conversion price of $8.568.

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

Holders' Demand Repurchase Rights. The holders of our convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes upon certain fundamental changes.

(d) The carrying amounts as of December 31, 2018 and 2017, are reflected net of discounts of $384 million and $414 million, respectively, associated with the equity component of our convertible and contingent convertible senior notes. This amount is being amortized based on the effective yield method through the first demand repurchase date as applicable.

(e) As of December 31, 2018, net current maturities of long-term debt includes our Floating Rate Senior Notes due April 2019 and our 2.25% Contingent Convertible Senior Notes due 2038.

Debt maturities for the next five years and thereafter are as follows:

	Principal Amount of Debt Securities
	($ in millions)
2019	$ 381
2020	664
2021	815
2022	451
2023	757
Thereafter	5,100
Total	$ 8,168

Debt Issuances and Retirements 2018

We issued at par $850 million of 7.00% Senior Notes due 2024 ("2024 notes") and $400 million of 7.50% Senior Notes due 2026 ("2026 notes") pursuant to a public offering for net proceeds of approximately $1.236 billion. We may redeem some or all of the 2024 notes at any time prior to April 1, 2021 and some or all of the 2026 notes at any time prior to October 1, 2021, in each case at a price equal to 100% of the principal amount of the notes to be redeemed plus a "make-whole" premium. At any time prior to April 1, 2021, with respect to the 2024 notes, and October 1, 2021, with respect to the 2026 notes, we also may redeem up to 35% of the aggregate principal amount of each series of notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a specified redemption price. In addition, we may redeem some or all of the 2024 notes at any time on or after April 1, 2021 and some or all of the 2026 notes at any time on or after October 1, 2021, in each case at the redemption prices in accordance with the terms of the notes and the indenture and supplemental indenture governing the notes. These senior notes are unsecured obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our obligations under the senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries.

We used the net proceeds from the 2024 and 2026 notes, together with cash on hand and borrowings under the Chesapeake revolving credit facility, to repay in full $1.233 billion of borrowings under our secured term loan due 2021 for $1.285 billion, which included a $52 million make-whole premium. We recorded a loss of approximately $65 million associated with the repayment of the term loan, including the make-whole premium and the write-off of $13 million of associated deferred charges.

We used a portion of the proceeds from the sale of our Utica Shale assets in Ohio to redeem all of the $1.416 billion aggregate principal amount outstanding of our 8.00% Senior Secured Second Lien Notes due 2022 for $1.477 billion. We recorded a gain of approximately $331 million associated with the redemption, including the realization of the remaining $391 million difference in principal and book value due to troubled debt restructuring accounting in 2015, offset by the make-whole premium of $60 million.

We repaid upon maturity $44 million principal amount of our 7.25% Senior Notes due 2018.

As required by the terms of the indenture for our 2.25% Contingent Convertible Senior Notes due 2038 (“2038 notes”), the holders were provided the option to require us to purchase on December 15, 2018, all or a portion of the holders’ 2038 notes at par plus accrued and unpaid interest up to, but excluding, December 15, 2018. On December 17, 2018, we paid an aggregate of approximately $8 million to purchase all of the 2038 notes that were tendered and not withdrawn. An aggregate of $1 million principal amount of the 2038 notes remained outstanding as of December 31, 2018. Subsequent to December 31, 2018, we redeemed these notes at par and discharged the related indenture.

Debt Issuances and Retirements - 2017

We issued through two private placements $1.300 billion aggregate principal amount of unsecured 8.00% Senior Notes due 2027 for net proceeds of approximately $1.285 billion. The first private placement was issued at par and the second private placement was issued at 99.75% of par. Some or all of the notes may be redeemed at any time prior to June 15, 2022, subject to a make-whole premium. We also may redeem some or all of the notes at any time on or after June 15, 2022, at the applicable redemption price in accordance with the terms of the notes and the indenture and supplemental indenture governing the notes. In addition, subject to certain conditions, we may redeem up to 35% of the aggregate principal amount of the notes at any time prior to June 15, 2020, at a price equal to 108% of the principal amount of the notes to be redeemed using the net proceeds of certain equity offerings.

We also issued in a private placement $300 million aggregate principal amount of additional 8.00% Senior Notes due 2025 (“new 2025 notes”) at 101.25% of par for net proceeds of $301 million. The new 2025 notes are an additional issuance of our outstanding 8.00% Senior Notes due 2025, which we issued in 2016 in an original aggregate principal amount of $1.0 billion at 98.52% of par. The new 2025 Notes issued and the previously issued senior notes due 2025 will be treated as a single class of notes under the indenture.

We retired $2.389 billion principal amount of our outstanding senior notes, senior secured second lien notes, contingent convertible notes and term loan through purchases in the open market, tender offers or repayment upon maturity for $2.592 billion using proceeds from the issuances described above. For the open market repurchases and tender offers, we recorded a net aggregate gain of approximately $233 million, including $374 million of premium associated with our 8.00% Senior Secured Second Lien Notes due 2022.

Senior Notes and Convertible Senior Notes

Our senior notes and our convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our obligations under the senior notes and the convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries. See Note 25 for consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

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

Chesapeake Revolving Credit Facility

In 2018, we amended and restated our credit agreement dated December 15, 2014. The amended and restated Chesapeake revolving credit facility matures in September 2023 and the aggregate initial commitment of the lenders and borrowing base under the facility is $3.0 billion. The Chesapeake revolving credit facility provides for an accordion feature, pursuant to which the aggregate commitments thereunder may be increased to up to $4.0 billion from time to time, subject to agreement of the participating lenders and certain other customary conditions. Borrowing base redeterminations will continue to occur semiannually and our next borrowing base redetermination is scheduled for the second quarter of 2019. As of December 31, 2018, we had outstanding borrowings of $419 million under the Chesapeake revolving credit facility and had used $107 million of the Chesapeake revolving credit facility for various letters of credit. We recorded a loss of $3 million associated with certain deferred charges related to the Chesapeake revolving credit facility prior to its amendment and restatement.

Borrowings under the Chesapeake revolving credit facility bear interest at an alternative base rate (ABR) or LIBOR, at our election, plus an applicable margin ranging from 0.50%-2.00% per annum for ABR loans and 1.50%-3.00% per annum for LIBOR loans, depending on the percentage of the borrowing base then being utilized and whether our leverage ratio exceeds 4.00 to 1.

The Chesapeake 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, incur liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates. The Chesapeake revolving credit facility contains financial covenants that, after the suspension of most of the covenants during the fourth quarter of 2018 as a result of the closing of the sale of certain of our Utica Shale, beginning in the first quarter of 2019, require us to maintain (i) a leverage ratio of not more than 5.50 to 1 through the fiscal quarter ending September 30, 2019, which threshold decreases over time to 4.00 to 1 for the fiscal quarter ending March 31, 2021 and each fiscal quarter thereafter, (ii) a secured leverage ratio of not more than 2.50 to 1 until the later of (x) the fiscal quarter ending March 31, 2021 or (y) the fiscal quarter in when the Company's leverage ratio does not exceed 4.00 to 1 and (iii) a fixed charge coverage ratio of not less than 2.00 to 1 through the fiscal quarter ending December 31, 2019; not less than 2.25 to 1 through the fiscal quarter ending June 30, 2020; and not less than 2.50 to 1 for the fiscal quarter ended September 30, 2020 and thereafter.

For the fiscal quarter ended December 31, 2018, our only applicable financial covenant required us to maintain a leverage ratio of not more than 5.50 to 1.

As of December 31, 2018, we were in compliance with all applicable financial covenants under the credit agreement and we were able to borrow up to the full availability under the Chesapeake 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:

	December 31, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$ 381	$ 379	$ 52	$ 53
Long-term debt (Level 1)	$ 3,495	$ 3,173	$ 2,633	$ 2,629
Long-term debt (Level 2)	$ 3,846	$ 3,644	$ 7,286	$ 7,301

5. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

We are involved in a number of litigation and regulatory proceedings including those described below. Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. Our total accrued liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different.

Business Operations. We are involved in various lawsuits and disputes incidental to our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Regarding royalty claims, we and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, that we used below-market prices, made improper deductions, utilized improper measurement techniques entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL, or similar theories. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The lawsuits seek compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. Plaintiffs have varying royalty provisions in their respective leases, oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. We have resolved a number of these claims through negotiated settlements of past and future royalty obligations and have prevailed in various other lawsuits. We are currently defending numerous lawsuits seeking damages with respect to underpayment of royalties in multiple states where we have operated, including those discussed below.

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

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the divestiture of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights, intentional interference with contractual relations, and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources. These lawsuits seek in aggregate compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. On December 20, 2017 and August 9, 2018, we reached tentative settlements to resolve substantially all Pennsylvania civil royalty cases for a total of approximately $35 million.

We believe losses are reasonably possible in certain of the pending royalty cases for which we have not accrued a loss contingency, but we are currently unable to estimate an amount or range of loss or the impact the actions could have on our future results of operations or cash flows. Uncertainties in pending royalty cases generally include the complex nature of the claims and defenses, the potential size of the class in class actions, the scope and types of the properties and agreements involved, and the applicable production years.

We 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 insignificant amount. The final fairness hearing is set for April 25, 2019.

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. On November 13, 2018, a unanimous panel denied every claim asserted by OOGC other than OOGC being entitled to a declaration clarifying its audit rights.

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 we 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.

In February 2019, a putative class action lawsuit in the District Court of Dallas County, Texas was filed against FTS International, Inc. ("FTSI"), certain investment banks, FTSI's directors including certain of our officers and certain shareholders of FTSI including us. The lawsuit alleges various violations of Sections 11 (with respect to certain of our officers in their capacities as directors of FTSI) and 15 (with respect to such officers and us) of the Securities Act of 1933 in connection with public disclosure made during the initial public offering of FTSI. The suit seeks damages in excess of $1,000,000 and attorneys' fees and other expenses. We intend to vigorously defend these claims.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for us and our subsidiaries. We have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. We conduct periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, we may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.

We are named as a defendant in numerous lawsuits in Oklahoma alleging that we and other companies have engaged in activities that have caused earthquakes. These lawsuits seek compensation for injury to real and personal property, diminution of property value, economic losses due to business interruption, interference with the use and enjoyment of property, annoyance and inconvenience, personal injury and emotional distress. In addition, they seek the reimbursement of insurance premiums and the award of punitive damages, attorneys' fees, costs, expenses and interest.

Other Matters

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Commitments

Operating Leases

Future operating lease commitments related to other property and equipment are not recorded as obligations in the accompanying consolidated balance sheets. The aggregate undiscounted minimum future lease payments are presented below:

	December 31, 2018 ($ in millions)
2019	$ 3
2020	1
Total	$ 4

Operating lease expense for the years ended December 31, 2018, 2017 and 2016, was $4 million, $3 million and $5 million, respectively.

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:

	December 31, 2018 ($ in millions)
2019	$ 832
2020	774
2021	683
2022	581
2023	470
2024 – 2034	2,431
Total	$ 5,771

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.

Service Contract

We have a contract with a third-party contractor to provide maintenance and other services to our natural gas compressors under capital lease. This commitment is not recorded as an obligation in the accompanying consolidated balance sheets. The aggregate undiscounted minimum future payments under this service contract is detailed below.

	December 31, 2018
	($ in millions)
2019	$ 5
2020	5
2021	5
Total	$ 15

Other Commitments

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

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

While executing our strategic priorities, we have incurred certain cash charges, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity.

6. Other Liabilities

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

	December 31, 2018	December 31, 2017
	($ in millions)	
Revenues and royalties due others	$ 687	$ 612
Accrued drilling and production costs	258	216
Joint interest prepayments received	73	74
VPP deferred revenue[(a)]	59	63
Accrued compensation and benefits	202	214
Other accrued taxes	108	43
Other	212	296
Total other current liabilities	$ 1,599	$ 1,518

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

	December 31, 2018	December 31, 2017
	($ in millions)	
VPP deferred revenue[(a)]	$ 63	$ 122
CHK Utica ORRI conveyance obligation[(b)]	—	156
Unrecognized tax benefits	53	101
Other	103	97
Total other long-term liabilities	$ 219	$ 476

(a) At the inception of our volumetric production payment (VPP) agreements, we (i) removed the proved reserves associated with the VPP, (ii) recognized VPP proceeds as deferred revenue which are being amortized on a unit-of-production basis to other revenue over the term of the VPP, (iii) retained responsibility for the production costs and capital costs related to VPP interests and (iv) ceased recognizing production associated with the VPP volumes. The remaining deferred revenue balance will be recognized in other revenues in the consolidated statement of operations through 2021, assuming the related VPP production volumes are delivered as scheduled.

(b) In 2018, we repurchased a previously conveyed 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 2018 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 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 consolidated balance sheet.

7. Capital Lease Obligation

In 2018, we sold our wholly owned subsidiary, Midcon Compression, L.L.C., to a third party and subsequently leased back some natural gas compressors for 38 months. The aggregate undiscounted minimum future lease payments are presented below:

	December 31, 2018
	($ in millions)
2019	$ 10
2020	10
2021	10
Total minimum lease payments	30
Less imputed interest	(3)
Present value of minimum lease payments	27
Less current maturities	(10)
Present value of minimum lease payment, less current maturities	$ 17

8. 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 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 consolidated statements of operations was as follows:

	Before adoption of ASC 606	Adjustments	As Reported
		($ in millions)	
Statement of Operations for the Year Ended December 31, 2018			
Marketing revenues	$ 5,871	$ (795)	$ 5,076
Marketing operating expenses	$ 5,953	$ (795)	$ 5,158

The following table shows revenue disaggregated by operating area and product type, for the year ended December 31, 2018:

	Year Ended December 31, 2018			
	Oil	Natural Gas	NGL	Total
	($ in millions)			
Marcellus	$ —	$ 924	$ —	$ 924
Haynesville	2	836	—	838
Eagle Ford	1,514	173	185	1,872
Powder River Basin	244	68	38	350
Mid-Continent	246	84	55	385
Utica	195	401	224	820
Revenue from contracts with customers	2,201	2,486	502	5,189
Gains (losses) on oil, natural gas and NGL derivatives	124	(147)	(11)	(34)
Oil, natural gas and NGL revenue	$ 2,325	$ 2,339	$ 491	$ 5,155
Marketing revenue from contracts with customers	$ 2,740	$ 1,194	$ 456	$ 4,390
Other marketing revenue	457	229	—	686
Marketing revenue	$ 3,197	$ 1,423	$ 456	$ 5,076

Accounts Receivable

Accounts receivable as of December 31, 2018 and 2017 are detailed below:

	December 31,	
	2018	2017
	($ in millions)	
Oil, natural gas and NGL sales	$ 976	$ 959
Joint interest billings	211	209
Other	77	184
Allowance for doubtful accounts	(17)	(30)
Total accounts receivable, net	$ 1,247	$ 1,322

9. Income Taxes

The components of the income tax provision (benefit) for each of the periods presented below are as follows:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Current			
Federal	$ —	$ (14)	$ (14)
State	—	5	(5)
Current Income Taxes	—	(9)	(19)
Deferred			
Federal	3	13	(147)
State	(13)	(2)	(24)
Deferred Income Taxes	(10)	11	(171)
Total	$ (10)	$ 2	$ (190)

The effective income tax expense (benefit) differed from the computed "expected" federal income tax expense on earnings before income taxes for the following reasons:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (21%, 35%, 35%)	$ 45	$ (175)	$ (1,288)
State income taxes (net of federal income tax benefit)	27	5	33
Remeasurement of deferred tax assets and liabilities	—	931	—
Change in valuation allowance	(97)	(771)	1,042
Other	15	12	23
Total	$ (10)	$ 2	$ (190)

We applied the guidance in SAB 118 when accounting for the enactment-date effect of the Tax Act. At December 31, 2017, we had not completed our accounting for all of the enactment-date income tax effects of the Tax Act under ASC 740, Income Taxes, for certain items as we were waiting on additional guidance to be issued. At December 31, 2018, we have now completed our accounting for all of the enactment-date income tax effects of the Tax Act. The adjustments made during 2018 are considered immaterial but nevertheless are included as a component of income tax expense in our consolidated statement of operations for the year ended December 31, 2018, which is fully offset with an adjustment to the valuation allowance against our net deferred tax asset.

We reassessed the realizability of our deferred tax assets and continue to maintain a valuation allowance against all or substantially all of our net deferred tax asset. The $97 million net decrease in our valuation allowance is reflected as a component of income tax expense in our consolidated statement of operations for the year ended December 31, 2018. This decrease in the valuation allowance is primarily due to offsetting current year tax expense.

Deferred income taxes are provided to reflect temporary differences in the tax basis of assets and liabilities and their reported amounts in the financial statements. The tax-effected temporary differences, tax credits and net operating loss carryforwards that comprise our deferred taxes are as follows:

	Years Ended December 31,	
	2018	2017
	($ in millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ (976)	$ (580)
Volumetric production payments	(86)	(83)
Carrying value of debt	(95)	—
Derivative instruments	(56)	—
Other	(7)	(20)
Deferred tax liabilities	(1,220)	(683)
Deferred tax assets:		
Net operating loss carryforwards	2,737	2,248
Carrying value of debt	—	161
Disallowed business interest carryforward	194	—
Asset retirement obligations	40	42
Investments	111	140
Derivative instruments	—	18
Accrued liabilities	89	125
Other	60	71
Deferred tax assets	3,231	2,805
Valuation allowance	(2,011)	(2,119)
Deferred tax assets after valuation allowance	1,220	686
Net deferred tax assets	$ —	$ 3

As of December 31, 2018, we had federal NOL carryforwards of approximately $10.138 billion and state NOL carryforwards of approximately $10.688 billion, which excludes the NOL carryforwards related to unrecognized tax benefits. The associated deferred tax assets related to these federal and state NOL carryforwards were $2.129 billion and $608 million, respectively. The federal NOL carryforwards generated in tax years prior to 2018 expire between 2031 and 2037. As a result of the Tax Act, the 2018 federal NOL carryforward has no expiration. The value of these carryforwards depends on our ability to generate future taxable income. As of December 31, 2018 and 2017, we had deferred tax assets of $3.231 billion and $2.805 billion upon which we had a valuation allowance of $2.011 billion and $2.119 billion, respectively. Of the net change in the valuation allowance of $108 million for both federal and state deferred tax assets, $97 million is reflected as a component of income tax expense in the consolidated statement of operations and the remainder is reflected in components of stockholders' equity.

A valuation allowance against deferred tax assets, including NOL carryforwards and disallowed business interest, is recognized when it is more likely than not that all or some portion of the benefit from the deferred tax assets will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of existing taxable temporary differences, and tax planning strategies, as well as the current and forecasted business economics of our industry. Management assesses all available evidence, both positive and negative, to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objectively verifiable negative evidence is the cumulative loss incurred over the three-year period ended December 31, 2018. Such objective negative evidence limits our ability to consider various forms of subjective positive evidence, such as our projections for future income. Accordingly, management has not changed its judgment for the period ended December 31, 2018 with respect to the need for a valuation allowance against all or substantially all of our net deferred tax asset position. The amount of the deferred tax asset considered realizable could be adjusted if projections of future taxable income are increased and/or if objective negative evidence in the form of cumulative losses is no longer present. Based on our current forecast, we may come out of a three-year cumulative loss position in the foreseeable future. Should we return to a level of sustained profitability, consideration will need to be given to future projections of taxable income to determine whether such projections provide an adequate source of taxable income for the realization of our deferred tax assets, namely federal NOL carryforwards and disallowed business interest carryforwards. If so, then all or a portion of the valuation allowance could possibly be released.

Our ability to utilize NOL carryforwards and possibly other tax attributes to reduce future federal taxable income and federal income tax is subject to various limitations under Section 382 of the Code. The utilization of these attributes may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders (as such shareholders are defined in Treasury regulations), and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

As of December 31, 2018, we do not believe that an ownership change has occurred that would limit the utilization of our NOL carryforwards and other tax attributes. Certain future transactions involving our equity (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOL carryforwards and possibly other tax attributes.

Accounting guidance for recognizing and measuring uncertain tax positions requires a more likely than not threshold condition be met on a tax position, based solely on the technical merits of being sustained, before any benefit of the tax position can be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of uncertain tax positions. As of December 31, 2018 and 2017, the amount of unrecognized tax benefits related to NOL carryforwards and tax liabilities associated with uncertain tax positions was $79 million and $106 million, respectively. Of the 2018 amount, $32 million is related to state tax liabilities, $29 million is related to state tax receivables not expected to be recovered and the remainder is related to NOL carryforwards. Of the 2017 amount, $74 million is related to state tax liabilities, $4 million is related to federal tax liabilities and the remainder is related to NOL carryforwards. If recognized, $61 million of the uncertain tax positions identified would have an effect on the effective tax rate. No material changes to the current uncertain tax positions are expected within the next 12 months. As of December 31, 2018 and 2017, we had accrued liabilities of $20 million and $23 million, respectively, for interest related to these uncertain tax positions. We recognize interest related to uncertain tax positions as a component of interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	2018	2017	2016
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 106	$ 202	$ 280
Additions based on tax positions related to the current year	—	—	—
Additions to tax positions of prior years	—	4	33
Settlements	—	(100)	(111)
Expiration of the applicable statute of limitations	(23)	—	—
Reductions to tax positions of prior years	(4)	—	—
Unrecognized tax benefits at end of period	$ 79	$ 106	$ 202

Our federal and state income tax returns are subject to examination by federal and state tax authorities. Federal examination cycles 2010 through 2013 and 2014 through 2015 were settled with the Internal Revenue Service (IRS) during the first and third quarters of 2018, respectively. However, certain of these tax years remain open for purposes of adjusting federal net operating loss carryforwards upon utilization. Tax years 2016 through 2018 remain open for all purposes of examination by the IRS. In addition, tax years 2016 through 2018 as well as certain earlier years remain open for examination by state tax authorities. Currently, several state examinations are in progress of various years. We do not anticipate that the outcome of any state audit will have a significant impact on our results of operations or financial position.

10. Related Party Transactions

Our equity method investees are considered related parties. Hydraulic fracturing and other services are provided to us in the ordinary course of business by our equity affiliate FTSI. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs. For the years ended December 31, 2018, 2017 and 2016, our expenditures for hydraulic fracturing services with FTSI were $93 million, $111 million and $3 million, respectively.

11. Equity

Common Stock

A summary of the changes in our common shares issued for the years ended December 31, 2018, 2017 and 2016 is detailed below:

	Years Ended December 31,		
	2018	2017	2016
		(in thousands)	
Shares issued as of January 1	908,733	896,279	664,796
Restricted stock issuances (net of forfeitures and cancellations)	4,983	2,488	1,945
Exchange/conversion of preferred stock	—	9,966	120,186
Exchange of convertible notes	—	—	55,428
Exchange of senior notes	—	—	53,924
Shares issued as of December 31	913,716	908,733	896,279

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2018:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder's Conversion Right	Conversion Rate	Conversion Price	Company's Conversion Right From	Company's Market Conversion Trigger[(a)]
5.75% cumulative convertible non-voting	May and June 2010	$ 1,000	Any time	39.6858	$ 25.1979	May 17, 2015	$ 32.7573
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	38.3508	$ 26.0751	May 17, 2015	$ 33.8976
4.50% cumulative convertible	September 2005	$ 100	Any time	2.4561	$ 40.7152	September 15, 2010	$ 52.9298
5.00% cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.7745	$ 36.0431	November 15, 2010	$ 46.8560

(a) Convertible at the Company's option if the trading price of the Company's common stock equals or exceeds the trigger price for a specified time period or after the applicable conversion date if there are less than 250,000 shares of 4.50% or 5.00% (Series 2005B) preferred stock outstanding or 25,000 shares of 5.75% or 5.75% (Series A) preferred stock outstanding.

Outstanding shares of our preferred stock for the years ended December 31, 2018, 2017 and 2016 are detailed below:

	5.75%	5.75% (Series A)	4.50%	5.00% (Series 2005B)
	(in thousands)			
Shares outstanding as of January 1, 2018 and December 31, 2018	770	463	2,559	1,811
Shares outstanding as of January 1, 2017	843	476	2,559	1,962
Preferred stock conversions/exchanges[(a)]	(73)	(13)	—	(151)
Shares outstanding as of December 31, 2017	770	463	2,559	1,811
Shares outstanding as of January 1, 2016	1,497	1,100	2,559	2,096
Preferred stock conversions/exchanges[(b)]	(654)	(624)	—	(134)
Shares outstanding as of December 31, 2016	843	476	2,559	1,962

(a) During 2017, holders of our 5.75% Cumulative Convertible Preferred Stock exchanged 72,600 shares into 7,442,156 shares of common stock, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock exchanged 12,500 shares into 1,205,923 shares of common stock and holders of our 5.00% (Series 2005B) Cumulative Convertible Preferred Stock exchanged 150,948 shares into 1,317,756 shares of common stock. In connection with the exchanges, we recognized a loss equal to the excess of the fair value of all common stock issued in exchange for the preferred stock over the fair value of the common stock issuable pursuant to the original terms of the preferred stock. The loss of $41 million is reflected as a reduction to net income available to common stockholders for the purpose of calculating earnings per common share.

(b) During 2016, holders of our 5.75% Cumulative Convertible Preferred Stock converted 653,872 shares into 59,141,429 shares of common stock, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock converted 624,137 shares into 60,032,734 shares of common stock and holders of our 5.00% (Series 2005B) Cumulative Convertible Preferred Stock exchanged or converted 134,000 shares into 1,012,032 shares of common stock. In connection with the exchanges noted above, we recognized a loss equal to the excess of the fair value of all common stock issued in exchange for the preferred stock over the fair value of the common stock issuable pursuant to the original terms of the preferred stock. The loss of $428 million is reflected as a reduction to net income available to common stockholders for the purpose of calculating earnings per common share.

Dividends

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

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

In January 2016, we suspended dividend payments on our convertible preferred stock to provide additional liquidity in the depressed commodity price environment. In the first quarter of 2017, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock and paid our dividends in arrears.

Accumulated Other Comprehensive Income (Loss)

For the years ended December 31, 2018 and 2017, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below:

	Years Ended December 31,	
	2018	2017
	($ in millions)	
Balance, as of January 1	$ (57)	$ (96)
Other comprehensive income before reclassifications	—	5
Amounts reclassified from accumulated other comprehensive income[(a)]	34	34
Net other comprehensive income	34	39
Balance, as of December 31	$ (23)	$ (57)

(a) Net losses on cash flow hedges for commodity contracts reclassified from accumulated other comprehensive income (loss), net of tax, to oil, natural gas and NGL revenues in the consolidated statements of operations.

Noncontrolling Interests

Chesapeake Granite Wash Trust. We own 23,750,000 common units in the Chesapeake Granite Wash Trust (the Trust) representing a 51% beneficial interest. We have determined that the Trust is a VIE and that we are the primary beneficiary. As a result, the Trust is included in our consolidated financial statements. As of December 31, 2018 and 2017, we had $41 million and $44 million, respectively, of noncontrolling interests on our consolidated balance sheets attributable to the Trust. Net income attributable to the Trust’s noncontrolling interest was $2 million, $3 million and $3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The Trust’s legal existence is separate from Chesapeake and our other consolidated subsidiaries, and the Trust is not a guarantor of any of Chesapeake’s debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake. We have presented parenthetically on the face of the consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

12. 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 Plan. The restricted stock and stock options are equity-classified awards and the PSUs and CRSUs are liability-classified awards.

Share-Based Compensation Plans

2014 Long Term Incentive Plan. Our 2014 Long Term Incentive Plan (2014 LTIP), which is administered by the Compensation Committee of our Board of Directors, became effective on June 13, 2014 after it was approved by shareholders at our 2014 Annual Meeting. The 2014 LTIP replaced our Amended and Restated Long Term Incentive Plan which was adopted in 2005. The 2014 LTIP provides for up to 71,600,000 shares of common stock that may be issued as long-term incentive compensation to our employees and non-employee directors; provided, however, that the 2014 LTIP uses a fungible share pool under which (i) each share issued pursuant to a stock option or stock appreciation right (SAR) reduces the number of shares available under the 2014 LTIP by 1.0 share; (ii) each share issued pursuant to awards other than options and SARs reduces the number of shares available by 2.12 shares; (iii) if any awards of restricted stock under the 2014 LTIP, or its predecessor plan, are forfeited, expire, are settled for cash, or are tendered by the participant or withheld by us to satisfy any tax withholding obligation, then the shares subject to the award may be used again for awards; and (iv) PSUs and other performance awards which are payable solely in cash are not counted against the aggregate number of shares issuable. In addition, the 2014 LTIP prohibits the reuse of shares withheld or delivered to satisfy the exercise price of, or to satisfy tax withholding requirements for, an option or SAR. The 2014 LTIP also prohibits “net share counting” upon the exercise of options or SARs.

The 2014 LTIP authorizes the issuance of the following types of awards: (i) nonqualified and incentive stock options; (ii) SARs; (iii) restricted stock; (iv) performance awards, including PSUs; and (v) other stock-based awards. For both stock options and SARs, the exercise price may not be less than the fair market value of our common stock on the date of grant and the maximum exercise period may not exceed ten years from the date of grant. Awards granted under the plan vest at specified dates and/or upon the satisfaction of certain performance or other criteria, as determined by the Compensation Committee. As of December 31, 2018, 35,389,825 shares of common stock remained issuable under the 2014 LTIP.

Equity-Classified Awards

Restricted Stock. We grant restricted stock to employees and non-employee directors. A summary of the changes in unvested restricted stock during 2018, 2017 and 2016 is presented below:

	Shares of Unvested Restricted Stock	Weighted Average Grant Date Fair Value	
	(in thousands)		
Unvested restricted stock as of January 1, 2018	13,178	$	6.37
Granted	6,067	$	3.73
Vested	(5,808)	$	7.67
Forfeited	(1,579)	$	6.02
Unvested restricted stock as of December 31, 2018	11,858	$	4.43
Unvested restricted stock as of January 1, 2017	9,092	$	11.39
Granted	9,872	$	5.40
Vested	(4,573)	$	13.73
Forfeited	(1,213)	$	8.32
Unvested restricted stock as of December 31, 2017	13,178	$	6.37
Unvested restricted stock as of January 1, 2016	10,455	$	17.31
Granted	4,604	$	4.58
Vested	(4,692)	$	17.23
Forfeited	(1,275)	$	13.91
Unvested restricted stock as of December 31, 2016	9,092	$	11.39

The aggregate intrinsic value of restricted stock that vested during 2018 was approximately $20 million based on the stock price at the time of vesting.

As of December 31, 2018, there was approximately $33 million of total unrecognized compensation expense related to unvested restricted stock. The expense is expected to be recognized over a weighted average period of approximately 2.02 years.

Stock Options. In 2018, 2017 and 2016, 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 the 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 2018:

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 for 2018, 2017 and 2016:

	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	(1,198)	$ 5.45		
Outstanding as of December 31, 2018	18,096	$ 7.20	7.15	$ —
Exercisable as of December 31, 2018	8,250	$ 10.73	5.73	$ —
Outstanding as of January 1, 2017	8,593	$ 11.88	7.22	$ 14
Granted	9,226	$ 5.45		
Exercised	—	$ —		$ —
Expired	(435)	$ 18.50		
Forfeited	(1,099)	$ 9.12		
Outstanding as of December 31, 2017	16,285	$ 8.25	7.73	$ 1
Exercisable as of December 31, 2017	4,474	$ 15.15	5.26	$ —
Outstanding as of January 1, 2016	5,377	$ 19.37	5.80	$ —
Granted	4,932	$ 3.71		
Exercised	—	$ —		$ —
Expired	(771)	$ 19.46		
Forfeited	(945)	$ 5.66		
Outstanding as of December 31, 2016	8,593	$ 11.88	7.22	$ 14
Exercisable as of December 31, 2016	2,844	$ 19.60	5.53	$ —

(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 December 31, 2018, there was $13 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 1.56 years.

Restricted Stock and Stock Option Compensation. We recognized the following compensation costs, net of actual forfeitures, related to restricted stock and stock options for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
General and administrative expenses	$ 31	$ 43	$ 48
Oil and natural gas properties	2	5	6
Oil, natural gas and NGL production expenses	5	12	13
Exploration expenses	1	1	—
Marketing expenses	—	—	1
Total restricted stock and stock option compensation	$ 39	$ 61	$ 68

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 and the reporting date fair value of the 2017 awards. The performance period for the 2016 awards ended on December 31, 2018 and the TSR component has been finalized.

Grant Date Assumptions

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

Reporting Date Assumptions

Assumption	2017 Awards
Volatility	64.69%
Risk-free interest rate	2.63%
Dividend yield for value of awards	—%

As the above assumptions and expected satisfaction of performance metrics change, the PSU liabilities will be adjusted quarterly 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 PSU liability will be adjusted quarterly, based on changes in our stock price and expected satisfaction of performance metrics, through the end of each vesting period.

Cash Restricted Stock Units. In 2018, 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 CRSU liability will be adjusted quarterly, based on changes in our stock price, through the end of each vesting period.

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

	Units	Grant Date Fair Value	December 31, 2018 Fair Value	December 31, 2018 Vested Liability
		($ in millions)	($ in millions)	
2018 PSU Awards:				
Payable 2019, 2020 and 2021	3,959,647	$ 12	$ 11	$ —
2017 PSU Awards:				
Payable 2020	1,217,774	$ 8	$ 3	$ 1
2016 PSU Awards:				
Payable 2019	2,348,893	$ 10	$ 6	$ 4
2018 CRSU Awards:				
Payable 2019, 2020 and 2021	15,189,197	$ 46	$ 32	$ —

We recognized the following compensation costs (credits), net of actual forfeitures, related to our liability-classified awards for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31, 2018	2017	2016
	($ in millions)		
General and administrative expenses	$ 9	$ (4)	$ 14
Oil and natural gas properties	1	—	—
Oil, natural gas and NGL production expenses	2	—	—
Restructuring and other termination costs	—	—	1
Total liability-classified awards compensation	$ 12	$ (4)	$ 15

13. Employee Benefit Plans

Our qualified 401(k) profit sharing plan (401(k) Plan) is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the IRS. We match employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's base salary and performance bonus) in cash. We contributed $31 million, $35 million and $39 million to the 401(k) Plan in 2018, 2017 and 2016, respectively.

We also maintain a nonqualified deferred compensation plan (DC Plan). To be eligible to participate in the DC Plan, an active employee must have a base salary of at least $150,000, have a hire date on or before December 1, immediately preceding the year in which the employee is able to participate, or be designated as eligible to participate. We match 100% of employee contributions up to 15% of base salary and performance bonus in the aggregate for the DC Plan with Chesapeake common stock, and an employee who is at least age 55 may elect for the matching contributions to be made in any one of the DC Plan’s investment options. The maximum compensation that can be deferred by employees under all of our deferred compensation plans, including the Chesapeake 401(k) Plan, is a total of 75% of base salary and 100% of performance bonus. The participant may choose separate deferral election percentages for both plans. We contributed $7 million, $8 million and $9 million to the DC Plan during 2018, 2017 and 2016, respectively, to fund the match. The deferred compensation company match of 15% has a five-year vesting schedule based on years of service. Any participant who is active on December 31 of the plan year will receive the deferred compensation company match which will be awarded on an annual basis.

Any assets placed in trust by us to fund future obligations of our DC Plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company as to their deferred compensation in the plan.

14. 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 December 31, 2018 and 2017.

Oil, Natural Gas and NGL Derivatives

As of December 31, 2018 and 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 in exchange for a premium 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 December 31, 2018 and 2017 are provided below:

	December 31, 2018		December 31, 2017	
	Notional Volume	Fair Value	Notional Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	12	$ 157	21	$ (151)
Collars	8	98	—	—
Three-way collars	—	—	2	(10)
Call swaptions	—	—	2	(13)
Basis protection swaps	7	5	11	(9)
Total oil	27	260	36	(183)
Natural gas (bcf):				
Fixed-price swaps	623	26	532	149
Three-way collars	88	1	—	—
Collars	55	(3)	47	11
Call options	44	—	110	(3)
Call swaptions	106	(9)	—	—
Basis protection swaps	50	—	65	(7)
Total natural gas	966	15	754	150
NGL (mmgal):				
Fixed-price swaps	—	—	33	(2)
Contingent Consideration:				
Utica divestiture		7		—
Total estimated fair value		$ 282		$ (35)

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

Contingent Consideration Arrangements

In 2018, we sold our Utica Shale position to Encino. The agreement includes 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 prices for the months comprising the year 2022 equals or exceeds $3.00/mmbtu as calculated pursuant to the purchase agreement, and (ii) the average of the NYMEX natural gas strip price for the months comprising the year 2023 equals or exceeds $3.25/mmbtu as calculated pursuant to the purchase agreement. See Note 16 for further details regarding the transaction.

Foreign Currency Derivatives

During 2017, both our 6.25% Euro-denominated Senior Notes due 2017 and cross currency swaps for the same principal amount matured. Upon maturity of the notes, the counterparties paid us €246 million and we paid the counterparties $327 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. The swaps were designated as cash flow hedges and, because they were entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value did not impact earnings.

Supply Contract Derivatives

In 2016, we sold a long-term natural gas supply contract to a third party for cash proceeds of $146 million, which is included in marketing revenue as a realized gain. We reversed the cumulative unrealized gains, resulting in an unrealized loss of $297 million.

Effect of Derivative Instruments – Consolidated Balance Sheets

The following table presents the fair value and location of each classification of derivative instrument included in the consolidated balance sheets as of December 31, 2018 and 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 Sheets
		($ in millions)	
As of December 31, 2018			
Commodity Contracts:			
Short-term derivative asset	$ 306	$ (104)	$ 202
Long-term derivative asset	117	(41)	76
Short-term derivative liability	(107)	104	(3)
Long-term derivative liability	(41)	41	—
Contingent Consideration:			
Short-term derivative asset	7	—	7
Total derivatives	$ 282	$ —	$ 282
As of December 31, 2017			
Commodity Contracts:			
Short-term derivative asset	$ 157	$ (130)	$ 27
Short-term derivative liability	(188)	130	(58)
Long-term derivative liability	(4)	—	(4)
Total derivatives	$ (35)	$ —	$ (35)

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

Effect of Derivative Instruments – Consolidated Statements of Operations

The components of oil, natural gas and NGL revenues for the years ended December 31, 2018, 2017 and 2016 are presented below:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Oil, natural gas and NGL revenues	$ 5,189	$ 4,574	$ 3,866
Gains (losses) on undesignated oil, natural gas and NGL derivatives	—	445	(545)
Losses on terminated cash flow hedges	(34)	(34)	(33)
Total oil, natural gas and NGL revenues	$ 5,155	$ 4,985	$ 3,288

The components of marketing revenues for the years ended December 31, 2018, 2017 and 2016 are presented below:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Marketing revenues	$ 5,069	$ 4,511	$ 4,881
Gains on undesignated marketing natural gas derivatives	7	—	—
Losses on undesignated supply contract derivatives	—	—	(297)
Total marketing revenues	$ 5,076	$ 4,511	$ 4,584

Gains as a result of changes in the fair value of our contingent consideration arrangements are recognized in loss on sale of oil and natural gas properties in the consolidated statement of operations.

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:

	Years Ended December 31,					
	2018		2017		2016	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (114)	$ (57)	$ (153)	$ (96)	$ (160)	$ (99)
Net change in fair value	—	—	5	5	(27)	(13)
Losses reclassified to income	34	34	34	34	34	16
Balance, end of period	$ (80)	$ (23)	$ (114)	$ (57)	$ (153)	$ (96)

The accumulated other comprehensive loss as of December 31, 2018 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. Remaining deferred gain or loss amounts will be recognized in earnings in the month for which the original contract months are to occur. As of December 31, 2018, we expect to transfer approximately $34 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 December 31, 2018, our oil, natural gas and NGL derivative instruments were spread among 11 counterparties.

Hedging Arrangements

Certain of our hedging arrangements are with counterparties that are also lenders (or affiliates of lenders) under the Chesapeake revolving credit facility. The contracts entered into with these counterparties are secured by the same collateral that secures the Chesapeake 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 December 31, 2018, we posted an immaterial amount in letters of credit as collateral for our commodity derivatives. No cash was posted as collateral for our commodity 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 December 31, 2018 and 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 December 31, 2018				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 319	$ 103	$ 422
Commodity liabilities	—	(131)	(16)	(147)
Utica divestiture contingent consideration	—	—	7	7
Total derivatives	$ —	$ 188	$ 94	$ 282
As of December 31, 2017				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ —	$ 8	$ 8
Commodity liabilities	—	(20)	(23)	(43)
Total derivatives	$ —	$ (20)	$ (15)	$ (35)

A summary of the changes in the fair values of our financial assets (liabilities) classified as Level 3 during 2018 and 2017 is presented below:

	Commodity Derivatives	Utica Contingent Consideration
	($ in millions)	
Balance, as of January 1, 2018	$ (15)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	77	7
Total purchases, issuances, sales and settlements:		
Settlements	25	—
Balance, as of December 31, 2018	$ 87	$ 7
Balance, as of January 1, 2017	$ (10)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	2	—
Total purchases, issuances, sales and settlements:		
Settlements	(7)	—
Balance, as of December 31, 2017	$ (15)	$ —

(a)

	Commodity Derivatives		Utica Contingent Consideration	
	2018	2017	2018	2017
	($ in millions)			
Total gains included in earnings for the period	$ 77	$ 2	$ 7	$ —
Change in unrealized gains (losses) related to assets still held at reporting date	$ 86	$ (14)	$ 7	$ —

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

The significant unobservable inputs for Level 3 derivative contracts include market volatility. Changes in market volatility 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. The following table presents quantitative information about Level 3 inputs used in the fair value measurement of our commodity derivative contracts as of December 31, 2018:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2018
				($ in millions)
Oil trades	Oil price volatility curves	23.70% – 42.17%	32.51%	$ 98
Natural gas trades	Natural gas price volatility curves	12.88% – 90.93%	24.93%	$ (11)
Utica contingent consideration	Natural gas price volatility curves	10.36% – 57.66%	—	$ 7

15. Capitalized Exploratory Well Costs

A summary of the changes in our capitalized well costs for the years ended December 31, 2018, 2017 and 2016 is detailed below. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

	2018	2017	2016
		(in millions)	
Balance as of January 1	$ 36	$ 41	$ 48
Additions pending the determination of proved reserves	74	14	15
Divestitures and other	—	—	—
Reclassifications to proved properties	(40)	(19)	(22)
Charges to exploration expense	(34)	—	—
Balance as of December 31	$ 36	$ 36	$ 41

The following table provides an aging of capitalize costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

	2018	2017	2016
		(in millions)	
Exploratory well costs capitalized for a period of one year or less	$ 34	$ 4	$ 2
Exploratory well costs capitalized for a period greater than one year	2	32	39
Balance as of December 31	$ 36	$ 36	$ 41
Number of projects with exploratory well costs capitalized for a period greater than one year	7	6	5

16. Oil and Natural Gas Property Transactions

2018 Transactions

We sold 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 net proceeds of $1.868 billion to Encino, 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 prices for the months comprising the year 2022 equals or exceeds $3.00/mmbtu as calculated pursuant to the purchase agreement, and (ii) the average of the NYMEX natural gas strip prices for the months comprising the year 2023 equals or exceeds $3.25/mmbtu as calculated pursuant to the purchase agreement. We recognized a loss of approximately $273 million associated with the transaction.

In 2018, 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. We recognized a gain of approximately $12 million associated with the transactions. Also, in 2018, we received proceeds of approximately $37 million subject to customary closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

2017 Transactions

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, and recognized a gain of approximately $326 million. 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 2017, we received proceeds of approximately $350 million, net of post-closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

2016 Transactions

We conveyed our interests in the Barnett Shale operating area located in north central Texas and received from the buyer aggregate net proceeds of approximately $218 million and recognized a gain of approximately $192 million associated with the transaction. We sold approximately 212,000 net developed and undeveloped acres along with other property and equipment. We simultaneously terminated most of our future commitments associated with this asset. In connection with this disposition, we paid $361 million to terminate certain natural gas gathering and transportation agreements and paid $58 million to restructure a long-term sales agreement. We recognized $361 million of expense for the termination of contracts and deferred charges of $58 million for the restructured contract. The deferred charges will be amortized to marketing, gathering and compression revenue over the life of the agreement. Additionally, we recognized a charge of $284 million in 2016 related to the impairment of other fixed assets sold in the divestiture.

We sold the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia, Kentucky and Virginia for proceeds of $140 million. We sold an interest in approximately 1.3 million net acres, retaining all rights below the base of the Kope formation, and approximately 5,300 wells along with related gathering assets, and other property and equipment. Additionally, we recognized an impairment charge of $142 million in 2016 related to other fixed assets sold in the divestiture. In connection with this divestiture, we purchased the underlying interests in one of our remaining VPP transactions for $127 million. All of the acquired interests were conveyed in our divestiture and we no longer have any future obligations related to this VPP. Inclusive of the VPP, we recognized a gain of approximately $47 million associated with the transaction.

We acquired oil and natural gas properties in the Haynesville Shale for approximately $85 million.

We sold certain of our other noncore oil and natural gas properties for net proceeds of approximately $1.048 billion, after post-closing adjustments. In conjunction with certain of these sales, we purchased oil and natural gas interests previously sold to third parties in connection with four of our VPP transactions for approximately $259 million. Substantially all of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas. Inclusive of the VPPs, we recognized a gain of approximately $351 million associated with the transactions.

Assets Held for Sale

As of December 31 2017, we had $128 million of our assets located in the Mid-Continent that satisfied criteria to be considered held for sale. We sold these assets in 2018.

17. Other Property and Equipment

Other Property and Equipment

A summary of other property and equipment held for use and the estimated useful lives thereof is as follows:

	December 31,		Estimated Useful Life
	2018	2017	
	($ in millions)		(in years)
Buildings and improvements	$ 1,053	$ 1,093	10 – 39
Computer equipment	353	345	5
Natural gas compressors[(a)]	48	235	3 – 20
Land	106	126	
Other	161	187	5 – 20
Total other property and equipment, at cost	1,721	1,986	
Less: accumulated depreciation	(630)	(672)	
Total other property and equipment, net	$ 1,091	$ 1,314	

(a) Includes assets under capital lease of $27 million, less accumulated depreciation of $1 million, as of December 31, 2018. The related amortization expense for assets under capital lease is included in depreciation, depletion and amortization expense on our consolidated statement of operations.

18. Investments

In 2018, 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. In 2016, we recognized an other-than-temporary impairment of $119 million related to our Sundrop investment.

19. Impairments

Impairments of Oil and Natural Gas Properties

A summary of our impairments of oil and natural gas properties for the years ended December 31, 2018, 2017 and 2016 is as follows:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Impairments due to lower forecasted commodity prices	$ 23	$ 27	$ 73
Impairments due to reduction in future development[(a)]	—	560	—
Impairments due to anticipated sale	55	222	29
Total impairments of oil and natural gas properties	$ 78	$ 809	$ 102

(a) The impairment was the result of an updated development plan in 2017, which included a removal of PUDs from properties in the process of being divested in the Mid-Continent operating area.

Impairments of Fixed Assets

A summary of our impairments of fixed assets by asset class and other charges for the years ended December 31, 2018, 2017 and 2016 is as follows:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Natural gas compressors	$ 45	$ —	$ 21
Barnett Shale exit costs	—	—	284
Devonian Shale exit costs	—	—	142
Gathering systems	—	—	3
Buildings and land	4	5	11
Other	4	—	—
Total impairments of fixed assets and other	$ 53	$ 5	$ 461

Natural Gas Compressors. In 2018, we recorded a $45 million impairment related to 890 compressors for the difference between carrying value and the fair value of the assets. In 2016, we recorded a $13 million impairment related to obsolescence of 205 compressors. Additionally in 2016, we recorded an $8 million impairment related to 155 compressors for the difference between the aggregate sales price and carrying value.

Barnett Shale Exit Costs. In 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and recognized an impairment charge of $284 million related to other fixed assets sold in the divestiture.

Devonian Shale Exit Costs. In 2016, we sold the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia and Kentucky. We recognized an impairment charge of $142 million in 2016 related to other fixed assets sold in the divestiture.

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

20. Other Operating Expense

In 2017, we terminated future natural gas transportation commitments related to divested assets for cash payments of $126 million. Also in 2017, we paid $290 million to assign an oil transportation agreement to a third party. In 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and simultaneously terminated most of our future commitments associated with this asset. As a result of this transaction, we recognized $361 million of charges related to the termination of natural gas gathering and transportation agreements.

21. Restructuring and Other Termination Costs

Workforce Reductions

In 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 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 December 31, 2018	$ —

In 2016, we recognized $6 million of charges related to a reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary and the reductions in workforce resulting from the conveyance of our interests in the Barnett Shale and Devonian Shale operating areas.

22. 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 December 31, 2018 and 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 December 31, 2018				
Financial Assets (Liabilities):				
Other current assets	$ 50	$ —	$ —	$ 50
Other current liabilities	(51)	—	—	(51)
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 4 for information regarding fair value measurement of our debt instruments. See Note 14 for information regarding fair value measurement of our derivatives.

Nonrecurring Fair Value Measurements

See Note 19 regarding nonrecurring fair value measurements.

23. Asset Retirement Obligations

The components of the change in our asset retirement obligations are shown below:

	Years Ended December 31, 2018	2017
	($ in millions)	
Asset retirement obligations, beginning of period	$ 177	$ 261
Additions	3	5
Revisions	11	(34)
Settlements and disposals	(35)	(70)
Accretion expense	10	15
Asset retirement obligations, end of period	166	177
Less current portion	11	15
Asset retirement obligation, long-term	$ 155	$ 162

24. Major Customers

Sales to Valero Energy Corporation constituted approximately 10% of our total revenues (before the effects of hedging for the year ended December 31, 2018. Sales to Royal Dutch Shell PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the year ended December 31, 2017. Sales to BP PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the years ended December 31, 2016.

25. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 4 are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries on a senior unsecured basis. Subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries are non-guarantors.

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 December 31, 2018 and 2017 and for the years ended December 31, 2018 and 2017. This financial information may not necessarily be indicative of our results of operations, cash flows or financial position had these subsidiaries operated as independent entities.

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 4	$ 1	$ 1	$ (2)	$ 4
Other current assets	60	1,532	2	—	1,594
Intercompany receivable, net	6,671	—	—	(6,671)	—
Total Current Assets	6,735	1,533	3	(6,673)	1,598
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on successful efforts accounting, net	—	9,664	48	—	9,712
Other property and equipment, net	—	1,091	—	—	1,091
Property and equipment held for sale, net	—	15	—	—	15
Total Property and Equipment, Net	—	10,770	48	—	10,818
LONG-TERM ASSETS:					
Other long-term assets	26	293	—	—	319
Investments in subsidiaries and intercompany advances	3,248	9	—	(3,257)	—
TOTAL ASSETS	$ 10,009	$ 12,605	$ 51	$ (9,930)	$ 12,735
CURRENT LIABILITIES:					
Current liabilities	$ 523	$ 2,365	$ 1	$ (2)	$ 2,887
Intercompany payable, net	—	6,671	—	(6,671)	—
Total Current Liabilities	523	9,036	1	(6,673)	2,887
LONG-TERM LIABILITIES:					
Long-term debt, net	7,341	—	—	—	7,341
Other long-term liabilities	53	321	—	—	374
Total Long-Term Liabilities	7,394	321	—	—	7,715
EQUITY:					
Chesapeake stockholders' equity	2,092	3,248	9	(3,257)	2,092
Noncontrolling interests	—	—	41	—	41
Total Equity	2,092	3,248	50	(3,257)	2,133
TOTAL LIABILITIES AND EQUITY	$ 10,009	$ 12,605	$ 51	$ (9,930)	$ 12,735

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	1,365	3	(1)	1,521
Intercompany receivable, net	8,699	434	—	(9,133)	—
Total Current Assets	8,858	1,800	5	(9,137)	1,526
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties at cost, based on successful efforts accounting, net	—	11,666	55	—	11,721
Other property and equipment, net	—	1,314	—	—	1,314
Property and equipment held for sale, net	—	144	—	—	144
Total Property and Equipment, Net	—	13,124	55	—	13,179
LONG-TERM ASSETS:					
Other long-term assets	52	168	—	—	220
Investments in subsidiaries and intercompany advances	3,201	(38)	—	(3,163)	—
TOTAL ASSETS	$ 12,111	$ 15,054	$ 60	$ (12,300)	$ 14,925
CURRENT LIABILITIES:					
Current liabilities	$ 190	$ 2,231	$ 2	$ (4)	$ 2,419
Intercompany payable, net	—	9,081	52	(9,133)	—
Total Current Liabilities	190	11,312	54	(9,137)	2,419
LONG-TERM LIABILITIES:					
Long-term debt, net	9,921	—	—	—	9,921
Other long-term liabilities	101	541	—	—	642
Total Long-Term Liabilities	10,022	541	—	—	10,563
EQUITY:					
Chesapeake stockholders’ equity (deficit)	1,899	3,201	(38)	(3,163)	1,899
Noncontrolling interests	—	—	44	—	44
Total Equity	1,899	3,201	6	(3,163)	1,943
TOTAL LIABILITIES AND EQUITY	$ 12,111	$ 15,054	$ 60	$ (12,300)	$ 14,925

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES AND OTHER:					
Oil, natural gas and NGL	$ —	$ 5,136	$ 19	$ —	$ 5,155
Marketing	—	5,076	—	—	5,076
Total Revenues	—	10,212	19		10,231
Other	—	63	—	—	63
Losses on sales of assets	—	(264)	—	—	(264)
Total Revenues and Other	—	10,011	19	—	10,030
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	539	—	—	539
Oil, natural gas and NGL gathering, processing and transportation	—	1,391	7	—	1,398
Production taxes	—	123	1	—	124
Exploration	—	162	—	—	162
Marketing	—	5,158	—	—	5,158
General and administrative	2	332	1	—	335
Restructuring and other termination costs	—	38	—	—	38
Provision for legal contingencies, net	—	26	—	—	26
Depreciation, depletion and amortization	—	1,730	7	—	1,737
Impairments	—	131	—	—	131
Total Operating Expenses	2	9,630	16	—	9,648
INCOME (LOSS) FROM OPERATIONS	(2)	381	3	—	382
OTHER INCOME (EXPENSE):					
Interest expense	(631)	(2)	—	—	(633)
Gains on investments	—	139	—	—	139
Gains on purchases or exchanges of debt	263	—	—	—	263
Other income	3	64	—	—	67
Equity in net earnings of subsidiary	583	1	—	(584)	—
Total Other Income (Expense)	218	202	—	(584)	(164)
INCOME BEFORE INCOME TAXES	216	583	3	(584)	218
INCOME TAX BENEFIT	(10)	—	—	—	(10)
NET INCOME	226	583	3	(584)	228
Net income attributable to noncontrolling interests	—	—	(2)	—	(2)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	226	583	1	(584)	226
Other comprehensive income	—	34	—	—	34
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 226	$ 617	$ 1	$ (584)	$ 260

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2017
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES AND OTHER:					
Oil, natural gas and NGL	$ —	$ 4,962	$ 23	$ —	$ 4,985
Marketing	—	4,511	—	—	4,511
Total Revenues	—	9,473	23	—	9,496
Other	—	67	—	—	67
Gains on sales of assets	—	476	—	—	476
Total Revenues and Other	—	10,016	23	—	10,039
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	562	—	—	562
Oil, natural gas and NGL gathering, processing and transportation	—	1,463	8	—	1,471
Production taxes	—	88	1	—	89
Exploration	—	235	—	—	235
Marketing	—	4,598	—	—	4,598
General and administrative	1	330	2	—	333
Provision for legal contingencies, net	(79)	41	—	—	(38)
Depreciation, depletion and amortization	—	1,688	9	—	1,697
Impairments	—	814	—	—	814
Other operating expense	—	416	—	—	416
Total Operating Expenses	(78)	10,235	20	—	10,177
INCOME (LOSS) FROM OPERATIONS	78	(219)	3	—	(138)
OTHER INCOME (EXPENSE):					
Interest expense	(599)	(2)	—	—	(601)
Gains on purchases or exchanges of debt	233	—	—	—	233
Other income	1	5	—	—	6
Equity in net earnings of subsidiary	(216)	—	—	216	—
Total Other Income (Expense)	(581)	3	—	216	(362)
INCOME (LOSS) BEFORE INCOME TAXES	(503)	(216)	3	216	(500)
INCOME TAX EXPENSE	2	—	—	—	2
NET INCOME (LOSS)	(505)	(216)	3	216	(502)
Net income attributable to noncontrolling interests	—	—	(3)	—	(3)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(505)	(216)	—	216	(505)
Other comprehensive income	—	39	—	—	39
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (505)	$ (177)	$ —	$ 216	$ (466)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2018
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ 85	$ 1,642	$ 10	$ (7)	$ 1,730
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(1,848)	—	—	(1,848)
Acquisitions of proved and unproved properties	—	(128)	—	—	(128)
Proceeds from divestitures of proved and unproved properties	—	2,231	—	—	2,231
Additions to other property and equipment	—	(21)	—	—	(21)
Proceeds from sales of other property and equipment	—	147	—	—	147
Proceeds from sales of investments	—	74	—	—	74
Net Cash Provided by Investing Activities	—	455	—	—	455
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	11,697	—	—	—	11,697
Payments on revolving credit facility borrowings	(12,059)	—	—	—	(12,059)
Proceeds from issuance of senior notes, net	1,236	—	—	—	1,236
Cash paid to purchase debt	(2,813)	—	—	—	(2,813)
Cash paid for preferred stock dividends	(92)	—	—	—	(92)
Other financing activities	(26)	(123)	(13)	7	(155)
Intercompany advances, net	1,971	(1,974)	2	1	—
Net Cash Used In Financing Activities	(86)	(2,097)	(11)	8	(2,186)
Net decrease in cash and cash equivalents	(1)	—	(1)	1	(1)
Cash and cash equivalents, beginning of period	5	1	2	(3)	5
Cash and cash equivalents, end of period	$ 4	$ 1	$ 1	$ (2)	$ 4

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2017
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ 5	$ 466	$ 14	$ (10)	$ 475
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(2,113)	—	—	(2,113)
Acquisitions of proved and unproved properties	—	(88)	—	—	(88)
Proceeds from divestitures of proved and unproved properties	—	1,249	—	—	1,249
Additions to other property and equipment	—	(21)	—	—	(21)
Other investing activities	—	55	—	—	55
Net Cash Used In Investing Activities	—	(918)	—	—	(918)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	7,771	—	—	—	7,771
Payments on revolving credit facility borrowings	(6,990)	—	—	—	(6,990)
Proceeds from issuance of senior notes, net	1,585	—	—	—	1,585
Cash paid to purchase debt	(2,592)	—	—	—	(2,592)
Cash paid for preferred stock dividends	(183)	—	—	—	(183)
Other financing activities	(39)	(5)	(13)	32	(25)
Intercompany advances, net	(456)	456	—	—	—
Net Cash Provided by (Used In) Financing Activities	(904)	451	(13)	32	(434)
Net increase (decrease) in cash and cash equivalents	(899)	(1)	1	22	(877)
Cash and cash equivalents, beginning of period	904	2	1	(25)	882
Cash and cash equivalents, end of period	$ 5	$ 1	$ 2	$ (3)	$ 5

26. Subsequent Events

On January 31, 2019, our shareholders approved a proposal to amend our restated certificate of incorporation to increase the number of authorized shares of our stock from 2,000,000,000 shares to 3,000,000,000 shares.

On February 1, 2019, we acquired WildHorse Resource Development Corporation ("WildHorse"), an oil and gas company with operations in the Eagle Ford Shale and Austin Chalk formations in southeast Texas for approximately 717.3 million shares of our common stock and $381 million in cash, and the assumption of WildHorse's debt of $1.4 billion as of February 1, 2019. We funded the cash portion of the consideration through borrowings under our revolving credit facility.

On February 1, 2019, we entered into a first amendment (the "Chesapeake facility amendment") to our Chesapeake revolving credit facility. Among other things, the Chesapeake facility amendment (i) designated Brazos Valley Longhorn and its subsidiaries as unrestricted subsidiaries under the Chesapeake revolving credit facility and (ii) expressly permitted our initial investment in WildHorse under the limitations on investments covenant. As a result of Brazos Valley Longhorn and its subsidiaries being designated as unrestricted subsidiaries under the Chesapeake revolving credit facility, transactions between Brazos Valley Longhorn and its subsidiaries, on the one hand, and Chesapeake and its subsidiaries other than Brazos Valley Longhorn, BVL Finance Corp. and the other BVL Guarantors, on the other hand, are required to be on an arm's-length basis, subject to certain exceptions, and Chesapeake is limited in the amount of investments it can make in Brazos Valley Longhorn and its subsidiaries.

On February 1, 2019, Brazos Valley Longhorn, as successor by merger to WildHorse, entered into a sixth amendment (the "WildHorse facility amendment") to the Wildhorse revolving credit facility. Among other things, the WildHorse facility amendment (i) amended the merger covenant and the definition of change of control to permit our acquisition of WildHorse and (ii) permits borrowings under the WildHorse revolving credit facility to be used to redeem or repurchase the WildHorse senior notes so long as certain conditions are met.

On February 1, 2019, Brazos Valley Longhorn, as successor by merger to WildHorse, and BVL Finance Corp., entered into a fourth supplemental indenture (the "WildHorse supplemental indenture") to the WildHorse indenture. Pursuant to the Wildhorse supplemental indenture, (i) Brazos Valley Longhorn assumed the rights and obligations of WildHorse as issuer under the WildHorse indenture and (ii) BVL Finance Corp. was named as a co-issuer of the WildHorse senior notes under the WildHorse indenture. We will account for the WildHorse acquisition by applying the acquisition method of accounting, which requires the acquired assets and liabilities to be recorded at fair value as of the acquisition date.

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2018 and 2017 are as follows:

	2018 First Quarter	2018 Second Quarter	2018 Third Quarter	2018 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 2,524	$ 2,289	$ 2,424	$ 2,793
Income (loss) from operations	$ 42	$ (160)	$ 82	$ 418
Net income (loss) attributable to Chesapeake	$ 17	$ (249)	$ (146)	$ 604
Net income (loss) available to common stockholders	$ (6)	$ (272)	$ (169)	$ 576
Net income (loss) per common share:				
Basic	$ (0.01)	$ (0.30)	$ (0.19)	$ 0.63
Diluted	$ (0.01)	$ (0.30)	$ (0.19)	$ 0.57

	2017 First Quarter	2017 Second Quarter	2017 Third Quarter	2017 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 3,076	$ 2,333	$ 2,028	$ 2,602
Income from operations	$ 244	$ 207	$ (620)	$ 31
Net income (loss) attributable to Chesapeake	$ 93	$ 257	$ (775)	$ (80)
Net income (loss) available to common stockholders	$ 29	$ 237	$ (798)	$ (103)
Net income (loss) per common share:				
Basic	$ 0.03	$ 0.26	$ (0.88)	$ (0.11)
Diluted	$ 0.03	$ 0.26	$ (0.88)	$ (0.11)

Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities (unaudited)

Net Capitalized Costs

Capitalized costs related to our oil, natural gas and NGL producing activities are summarized as follows:

	December 31, 2018	December 31, 2017
	($ in millions)	
Oil and oil and natural gas properties:		
Proved	$ 25,407	$ 27,932
Unproved	1,561	2,024
Total	26,968	29,956
Less accumulated depreciation, depletion and amortization	(17,256)	(18,235)
Net capitalized costs[(a)]	$ 9,712	$ 11,721

(a) Net capitalized costs does not include $128 million of oil and natural gas assets held for sale net of depreciation, depletion and amortization as of December 31, 2017.

Unproved properties not subject to amortization as of December 31, 2018 and 2017, consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. We capitalized approximately $16 million, $19 million and $10 million of interest during 2018, 2017 and 2016, respectively, on significant investments in unproved properties. We will continue to evaluate our unproved properties, and although the timing of the ultimate evaluation or disposition of the properties cannot be determined, we can expect the majority of our unproved properties not held by production to be transferred into the amortization base over the next five years.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development

Costs incurred in oil and natural gas property acquisition, exploration and development activities which have been capitalized are summarized as follows:

	Years Ended December 31, 2018	2017	2016
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ 80	$ 23	$ 403
Unproved properties	56	74	117
Exploratory costs	80	22	38
Development costs	1,954	2,075	1,230
Costs incurred[(a)]	$ 2,170	$ 2,194	$ 1,788

(a) Includes capitalized interest and asset retirement obligations as follows:

	2018	2017	2016
Capitalized interest	$ 16	$ 19	$ 10
Asset retirement obligations[(b)]	$ 8	$ (34)	$ (57)

(b) Activity in 2017 and 2016 primarily reflects revisions as the result of decreased plugging and abandonment costs in certain of our operating areas.

In 2018, we invested approximately $807 million to convert 115 mmboe of PUDs to proved developed reserves.

Results of Operations from Oil, Natural Gas and NGL Producing Activities

Our results of operations from oil, natural gas and NGL producing activities are presented below for 2018, 2017 and 2016. The following table includes revenues and expenses associated directly with our oil, natural gas and NGL producing activities. It does not include any interest costs or indirect general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil, natural gas and NGL operations.

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Oil, natural gas and NGL sales	$ 5,155	$ 4,985	$ 3,288
Other revenue	63	67	207
Oil, natural gas and NGL production expenses	(539)	(562)	(710)
Oil, natural gas and NGL gathering, processing and transportation expenses	(1,398)	(1,471)	(1,855)
Production taxes	(124)	(89)	(74)
Exploration	(162)	(235)	(1,455)
Impairment of oil and natural gas properties	(78)	(809)	(102)
Depletion and depreciation	(1,665)	(1,615)	(1,594)
Imputed income tax provision[(a)]	(326)	(107)	808
Results of operations from oil, natural gas and NGL producing activities	$ 926	$ 164	$ (1,487)

(a) The imputed income tax provision is hypothetical (at the statutory tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision (benefit) will be payable (receivable).

Oil, Natural Gas and NGL Reserve Quantities

Our petroleum engineers and independent petroleum engineering firm estimated all of our proved reserves as of December 31, 2018, 2017 and 2016. Our independent petroleum engineering firm, Software Integrated Solutions, Division of Schlumberger Technology Corporation, estimated an aggregate of 80%, 83% and 70% of our estimated proved reserves (by volume) as of December 31, 2018, 2017 and 2016.

Proved oil, natural gas and NGL reserves are those quantities of oil, natural gas and NGL which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. Based on reserve reporting rules, the price is calculated using the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. A project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Developed oil, natural gas and NGL reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods where production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

The information provided below on our oil, natural gas and NGL reserves is presented in accordance with regulations prescribed by the SEC. Our reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. These changes could be material and could occur in the near term.

Presented below is a summary of changes in estimated reserves for 2018, 2017 and 2016:

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
December 31, 2018				
Proved reserves, beginning of period	260.2	8,600	218.6	1,912
Extensions, discoveries and other additions	56.3	1,162	19.8	270
Revisions of previous estimates	(30.5)	242	5.4	15
Production	(32.7)	(832)	(18.9)	(190)
Sale of reserves-in-place	(37.8)	(2,395)	(121.6)	(559)
Purchase of reserves-in-place	—	—	—	—
Proved reserves, end of period[(a)]	215.5	6,777	103.3	1,448
Proved developed reserves:				
Beginning of period	150.9	4,980	134.9	1,116
End of period	127.6	3,314	67.9	748
Proved undeveloped reserves:				
Beginning of period	109.3	3,620	83.6	796
End of period[(b)]	87.9	3,463	35.4	700

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
December 31, 2017				
Proved reserves, beginning of period	399.1	6,496	226.4	1,708
Extensions, discoveries and other additions	62.7	3,694	44.9	723
Revisions of previous estimates	(168.1)	(315)	(31.0)	(252)
Production	(32.7)	(878)	(20.9)	(200)
Sale of reserves-in-place	(0.9)	(418)	(0.8)	(71)
Purchase of reserves-in-place	0.1	21	—	4
Proved reserves, end of period[c]	260.2	8,600	218.6	1,912
Proved developed reserves:				
Beginning of period	200.4	5,126	134.1	1,189
End of period	150.9	4,980	134.9	1,116
Proved undeveloped reserves:				
Beginning of period	198.7	1,370	92.2	519
End of period[b]	109.3	3,620	83.6	796
December 31, 2016				
Proved reserves, beginning of period	313.7	6,041	183.5	1,504
Extensions, discoveries and other additions	191.2	1,798	89.0	580
Revisions of previous estimates	(58.9)	598	2.8	43
Production	(33.2)	(1,050)	(24.4)	(233)
Sale of reserves-in-place	(14.7)	(1,190)	(28.1)	(241)
Purchase of reserves-in-place	1.0	299	3.6	55
Proved reserves, end of period[d]	399.1	6,496	226.4	1,708
Proved developed reserves:				
Beginning of period	215.6	5,329	158.0	1,262
End of period	200.4	5,126	134.1	1,189
Proved undeveloped reserves:				
Beginning of period	98.1	712	25.5	242
End of period[b]	198.7	1,370	92.2	519

(a) Includes 1 mmbbl of oil, 17 bcf of natural gas and 2 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, of which 1 mmbbl of oil, 8 bcf of natural gas and 1 mmbbl of NGL are attributable to noncontrolling interest holders.

(b) As of December 31, 2018, 2017 and 2016, there were no PUDs that had remained undeveloped for five years or more.

(c) Includes 1 mmbbl of oil, 20 bcf of natural gas and 2 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, of which 1 mmbbl of oil, 10 bcf of natural gas and 1 mmbbl of NGL are attributable to the noncontrolling interest holders.

(d) Includes 1 mmbbl of oil, 23 bcf of natural gas and 2 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, of which 1 mmbbl of oil, 12 bcf of natural gas and 1 mmbbl of NGL are attributable to the noncontrolling interest holders.

During 2018, we sold 559 mmboe of proved reserves for approximately $1.8 billion primarily in the Utica and MidContinent. We recorded extensions and discoveries of 270 mmboe, primarily related to undeveloped well additions located in Marcellus and Powder River Basin operating areas. In addition, we recorded upward revisions of 28 mmboe due to higher oil, natural gas and NGL prices in 2018 partially offset by downward revisions of 13 mmboe due to ongoing portfolio evaluation including longer lateral and spacing adjustments. The oil and natural gas prices used in computing our reserves as of December 31, 2018, were $65.56 per bbl and $3.10 per mcf, respectively, before price differentials.

During 2017, we recorded extensions and discoveries of 723 mmboe primarily in the Gulf Coast, Marcellus and Utica due to longer lateral, successful drilling and additional allocated capital in our 5-year development plan. We recorded a downward revision of 327 mmboe from previous estimates due to an updated development plan in the Eagle Ford aligning up-spacing, our activity schedule and well performance. Additionally, PUDs were removed from properties in the Mid-Continent in the process of being divested. As of December 31, 2017, we did not have sufficient technical data to estimate the impact of enhanced completion techniques in Eagle Ford. The downward revision was partially offset by improved oil, natural gas and NGL prices in 2017 resulting in a 75 mmboe upward revision. The oil and natural gas prices used in computing our reserves as of December 31, 2017, were $51.34 per bbl and $2.98 per mcf, respectively, before price differentials.

During 2016, we sold 241 mmboe of proved reserves for approximately $898 million. We recorded extensions and discoveries of 580 mmboe, primarily related to undeveloped well additions located in Utica and Eagle Ford. In addition, we recorded upward revisions of 113 mmboe due to changes in previous estimates resulting from improved drilling and operating efficiencies, which includes the impact from lower operating and capital costs, partially offset by downward revisions of 70 mmboe which were primarily the result of lower oil, natural gas and NGL prices in 2016. The oil and natural gas prices used in computing our reserves as of December 31, 2016, were $42.75 per bbl and $2.49 per mcf, respectively, before price differentials.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards Codification Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2018, 2017 and 2016 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of oil, natural gas and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for that year. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Future cash inflows	$ 27,312 [(a)]	$ 26,412 [(b)]	$ 19,835 [(c)]
Future production costs	(5,946)	(7,044)	(6,800)
Future development costs	(4,032)	(4,977)	(3,621)
Future income tax provisions	(331)	—	(79)
Future net cash flows	17,003	14,391	9,335
Less effect of a 10% discount factor	(7,508)	(6,901)	(4,956)
Standardized measure of discounted future net cash flows[(d)]	$ 9,495	$ 7,490	$ 4,379

(a) Calculated using prices of $65.56 per bbl of oil and $3.10 per mcf of natural gas, before field differentials.

(b) Calculated using prices of $51.34 per bbl of oil and $2.98 per mcf of natural gas, before field differentials.

(c) Calculated using prices of $42.75 per bbl of oil and $2.49 per mcf of natural gas, before field differentials.

(d) Excludes discounted future net cash inflows attributable to production volumes sold to VPP buyers. See Note 6.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	Years Ended December 31,		
	2018	2017	2016
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 7,490	$ 4,379	$ 4,693
Sales of oil and natural gas produced, net of production costs and gathering, processing and transportation[(b)]	(3,128)	(2,452)	(1,227)
Net changes in prices and production costs	3,317	3,977	(1,210)
Extensions and discoveries, net of production and development costs	1,666	1,951	1,042
Changes in estimated future development costs	1,113	614	323
Previously estimated development costs incurred during the period	973	775	664
Revisions of previous quantity estimates	47	(1,255)	145
Purchase of reserves-in-place	—	3	394
Sales of reserves-in-place	(2,052)	(116)	13
Accretion of discount	749	441	473
Net change in income taxes	(32)	26	(8)
Changes in production rates and other	(648)	(853)	(923)
Standardized measure, end of period[(a)(c)]	$ 9,495	$ 7,490	$ 4,379

(a) The impact of cash flow hedges has not been included in any of the periods presented.

(b) Excludes gains and losses on derivatives.

(c) Effect of noncontrolling interest of the Chesapeake Granite Wash Trust is immaterial.