CHESAPEAKE
ENERGY

2016 ANNUAL REPORT

Dear Fellow Shareholders,

In 2016, Chesapeake made significant progress in strengthening our financial position and improving our operational efficiencies, thanks to the commitment of our outstanding employees and the competitive advantages within our assets. While the low commodity price environment remains a challenge, we continue to make improvements and drive value across every aspect of our business.

2016 PERFORMANCE HIGHLIGHTS

$11.3B
Reduction in total leverage since 2012

$331M
Annual savings in LOE and G&A expenses

25%
Improvement in TRIR

Operating responsibly is a top priority, and as a result of our environmental, health and safety efforts, our worksites were safer in 2016. We are extremely proud of our employees for minimizing our environmental footprint, reducing motor vehicle incidents by 22% and reducing our Total Recordable Incident Rate (TRIR) by 25% over 2015.

The strength of Chesapeake's portfolio continues to grow as we capture efficiencies and develop new ways to leverage our technology to increase the value of our assets. By the end of 2016, our portfolio contained approximately 5,600 locations with a rate of return above 40%, at a specified price deck of $3 per mcf for natural gas and $60 per barrel for oil. During 2016, we drilled laterals of 10,000 – 15,000 feet in three of our operating areas, creating faster payouts and improved capital efficiencies.

Between September 2015 and the end of January 2017, we delivered on our commitment to improve our financial health by eliminating approximately $4.0 billion of leverage from our capital structure, including a reduction in both debt and preferred stock obligations. The reaffirmation of our revolving credit facility in April 2016 was a significant achievement, as were the numerous transactions that addressed our near-term debt maturities, which further enhanced our liquidity. We also divested approximately $2.3 billion of noncore, non-operated or low-return assets, surpassing our goal of $2.0 billion. Combined with similar transactions, these efforts helped reduce our total leverage by more than 50%, or $11.3 billion, between 2012 and January 2017.

Our focus on capital efficiencies resulted in cost improvements across our operating areas and helped us maintain production comparable to 2015 despite a capital budget that was roughly half of our 2015 investment. Our employees further reduced our cash costs in lease operating expenses (LOE) and G&A, resulting in savings of $331 million from 2015. Additionally, our relentless focus on cash costs and capital efficiencies delivered the lowest production expense per boe and lowest finding and development costs across our peer group in 2016.

In 2016 we continued to optimize our gathering, processing and transportation expenses and future commitments, resulting in a reduction of $264 million in these expenses compared to 2015. By divesting our Barnett Shale asset, we eliminated $200 – $300 million of annual midstream commitments impacting EBITDA through 2019. Since 2014 we have achieved gathering, processing and transportation commitment reductions totaling approximately $7 billion, with additional reductions expected in 2017 of more than $500 million.

While we are pleased with the tremendous progress made in 2016, we have more work to do. We are committed to removing an additional $2 – $3 billion of debt. We are targeting a return to profitable and efficient growth, highlighted by a 10% exit-to-exit oil growth rate from the fourth quarter 2016 to the fourth quarter 2017 and an additional 20% exit-to-exit oil growth rate from the fourth quarter 2017 to the fourth quarter 2018. Reducing debt and increasing oil production, combined with our employees' tireless drive to lower cash costs, will enable us to reach an important financial goal — cash flow neutrality — which is achievable in 2018.

With six major assets offering significant growth potential and providing product and geographic diversity, we have great confidence in the competitiveness of our portfolio. Chesapeake's leadership team and our talented employees remain driven to create differential performance and long-term shareholder value while maintaining our outstanding environmental, health and safety record. Thank you for your investment in Chesapeake.

R. Brad Martin
Chairman of the Board

Robert D. Lawler
President, Chief Executive Officer and Director

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2016
[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __________ to __________
Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1395733**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6100 North Western Avenue	
Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	(Zip Code)

(405) 848-8000
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
Floating Rate Senior Notes due 2019	New York Stock Exchange
6.625% Senior Notes due 2020	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
6.125% Senior Notes due 2021	New York Stock Exchange
5.375% Senior Notes due 2021	New York Stock Exchange
4.875% Senior Notes due 2022	New York Stock Exchange
5.75% Senior Notes due 2023	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
2.5% Contingent Convertible Senior Notes due 2037	New York Stock Exchange
2.25% Contingent Convertible Senior Notes due 2038	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES [X] NO [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES [ ] NO [X]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES [X] NO [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer [X] Accelerated Filer [ ] Non-accelerated Filer [ ] Smaller Reporting Company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES [ ] NO [X]

The aggregate market value of our common stock held by non-affiliates on June 30, 2016, was approximately $3.3 billion. As of February 22, 2017, there were 906,830,905 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2017 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
2016 ANNUAL REPORT ON FORM 10-K
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PART I

Item 1. *Business*

Unless the context otherwise requires, references to “Chesapeake”, the “Company”, “us”, “we” and “our” in this report are to Chesapeake Energy Corporation together with its subsidiaries. Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, and our main telephone number at that location is (405) 848-8000. Definitions of oil and gas industry terms appearing in this report can be found under *Glossary of Oil and Gas Terms* beginning on page 18.

Our Business

We own interests in approximately 22,700 oil and natural gas wells and produced an average of approximately 575 mboe per day in the 2016 fourth quarter, net to our interest. We have a large and geographically diverse resource base of onshore U.S. unconventional natural gas and liquids assets. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas, the Utica Shale in Ohio, the Anadarko Basin in northwestern Oklahoma and the stacked pay in the Powder River Basin in Wyoming. Our natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas and the Marcellus Shale in the northern Appalachian Basin in Pennsylvania. We also own an oil and natural gas marketing business.

The Company's estimated proved reserves as of December 31, 2016, were 1.708 bboe, an increase of 204 mmboe or 14%, from 1.504 bboe as of December 31, 2015. The increase in estimated proved reserves included 70 mmboe of downward revisions resulting primarily from lower average oil and natural gas prices offset by 580 mmboe of extensions and discoveries and 113 mmboe of upward revisions resulting from changes to previous estimates as further discussed below in *Oil, Natural Gas and NGL Reserves* and in *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report. In 2016, we produced 233 mmboe, divested 241 mmboe and acquired 55 mmboe of estimated proved reserves. Before basis differential adjustments, oil and natural gas prices used in estimating proved reserves decreased as of December 31, 2016, compared to December 31, 2015, using the trailing 12-month average prices required by the Securities and Exchange Commission (SEC). Oil prices decreased by $7.53 per bbl or 15%, to $42.75 per bbl from $50.28 per bbl. Natural gas prices decreased $0.09 per mcf, or 3%, to $2.49 per mcf from $2.58 per mcf. Proved developed reserves represented 70% of our proved reserves as of December 31, 2016, compared to 84% as of December 31, 2015.

Our daily production for 2016 averaged 635 mboe, a decrease of 44 mboe, or 6%, from the 679 mboe of daily production for 2015, and consisted of approximately 90,800 bbls of oil (14% on an oil equivalent basis), approximately 2.9 bcf of natural gas (75% on an oil equivalent basis) and approximately 66,700 bbls of NGL (11% on an oil equivalent basis). Our average daily oil production decreased by 20% year over year primarily as a result of the sale of certain of our Mid-Continent assets in 2015 and 2016 as well as a significant reduction in drilling activity. Natural gas production decreased by 2% and NGL production decreased by 13%.

Information About Us

We make available, free of charge on our website at *chk.com,* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of all recent news releases. Documents and information on our website are not incorporated by reference herein.

Business Strategy

Chesapeake's strategy is to create shareholder value through the development of our significant positions in premier U.S. onshore resource plays. In addition, we continue to focus our financial strategy on reducing debt and improving margins. We apply financial discipline to all aspects of our business with goals of increasing financial and operational flexibility. Our capital program is focused on investments that can improve our cash flow generating ability regardless of the commodity price environment. We plan to increase our capital expenditures in 2017 over 2016 levels to capture high rate of return opportunities in our oil and natural gas portfolio. These opportunities are a result of improved capital and operating efficiencies, including improved well performance, decreased drilling and completion costs per foot and decreased operating expenditures. We expect our anticipated production increases in the 2017 second half and into 2018 will position us to balance capital expenditures and operating cash flow in 2018 and beyond.

In 2016, we amended our senior secured revolving bank credit facility, issued a $1.5 billion secured term loan, issued $1.25 billion in 5.5% convertible senior notes due 2026, issued $1.0 billion in unsecured 8.00% senior notes due 2025 and sold approximately $1.4 billion of assets that did not fit our strategic priorities to increase liquidity and retire or refinance near-term maturities of debt. In addition, in 2016 and through February 24, 2017, we strengthened our balance sheet and improved our liquidity position by refinancing, exchanging or repurchasing, where possible at a discount, $4.104 billion of our debt and $1.4 billion liquidation value of our preferred equity instruments.

Our substantial inventory of hydrocarbon resources, including our undeveloped acreage, provides a strong foundation to create future value. Our focus on efficiencies and operational improvements has led to increased well productivity from longer laterals, improved completion techniques and base production improvements. Building on our strong and diverse asset base through increasing production and cash flow and further delineating our emerging new development opportunities, we believe that our dedication to financial discipline, the flexibility of our capital program, and our continued focus on safety and environmental stewardship will provide opportunities to create value for Chesapeake and its stakeholders in 2017 and beyond.

Operating Divisions

Chesapeake focuses its exploration, development, acquisition and production efforts in the two geographic operating divisions described below.

Southern Division. Includes the Eagle Ford Shale in South Texas, the Anadarko Basin in northwestern Oklahoma, the Haynesville/Bossier Shales in northwestern Louisiana and East Texas and, prior to October 31, 2016, the Barnett Shale in the Fort Worth Basin in north central Texas.

Northern Division. Includes the Utica Shale in Ohio, the Marcellus Shale in the northern Appalachian Basin in Pennsylvania and the stacked pay in the Powder River Basin in Wyoming.

Well Data

As of December 31, 2016, we held an interest in approximately 22,700 gross (8,800 net) productive wells, including 19,100 properties in which we held a working interest and 3,600 properties in which we held an overriding or royalty interest. Of the wells in which we had a working interest, 14,500 gross (6,700 net) were classified as natural gas productive wells and 4,600 gross (2,100 net) were classified as oil productive wells. Chesapeake operated approximately 10,900 of its 19,100 productive wells in which we had a working interest. During 2016, we drilled or participated in 382 gross (235 net) wells as operator and participated in another 53 gross (4 net) wells completed by other operators. We operate approximately 93% of our current daily production volumes.

Drilling Activity

The following table sets forth the wells we drilled or participated in during the periods indicated. In the table, "gross" refers to the total wells in which we had a working interest and "net" refers to gross wells multiplied by our working interest.

	2016				2015				2014			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	431	99	236	99	806	99	423	100	1,784	99	629	99
Dry	1	1	1	1	1	1	—	—	3	1	1	1
Total	432	100	237	100	807	100	423	100	1,787	100	630	100
Exploratory:												
Productive	3	100	2	100	7	100	5	100	145	95	46	88
Dry	—	—	—	—	—	—	—	—	8	5	6	12
Total	3	100	2	100	7	100	5	100	153	100	52	100

The following table shows the wells we drilled or participated in by operating division:

	2016		2015		2014	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Southern	375	212	537	258	1,448	473
Northern	60	27	277	170	492	209
Total	435	239	814	428	1,940	682

As of December 31, 2016, we had 140 gross (93 net) wells in the process of being drilled or completed.

Production, Sales Prices, Production and Gathering, Processing and Transportation Expenses

The following table sets forth information regarding our production volumes, oil, natural gas and NGL sales, average sales prices received and production and gathering, processing and transportation expenses for the periods indicated:

	Years Ended December 31,		
	2016	**2015**	**2014**
Net Production:			
Oil (mmbbl)	33	42	42
Natural gas (bcf)	1,049	1,070	1,095
NGL (mmbbl)	24	28	33
Oil equivalent (mmboe)[(a)]	233	248	258
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 40.65	$ 45.77	$ 89.41
Natural gas ($ per mcf)	$ 2.05	$ 2.31	$ 4.14
NGL ($ per bbl)	$ 14.76	$ 14.06	$ 30.95
Oil equivalent ($ per boe)	$ 16.63	$ 19.23	$ 36.21
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 43.58	$ 66.91	$ 85.04
Natural gas ($ per mcf)	$ 2.20	$ 2.72	$ 3.97
NGL ($ per bbl)	$ 14.43	$ 14.06	$ 30.95
Oil equivalent ($ per boe)	$ 17.66	$ 24.54	$ 34.74
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 3.05	$ 4.22	$ 4.69
Oil, natural gas and NGL gathering, processing and transportation	$ 7.98	$ 8.55	$ 8.43

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

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2016, with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at an annual rate of 10%) of estimated future net revenue before and after future income taxes (standardized measure). Neither the pre-tax present value of estimated future net revenue nor the after-tax standardized measure is intended to represent the current market value of the estimated oil, natural gas and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2016			
	Oil	Natural Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
Proved developed	200	5,126	134	1,189
Proved undeveloped	199	1,370	92	519
Total proved[(a)]	399	6,496	226	1,708

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[(b)]	$ 6,415	$ 2,999	$ 9,414
Present value of estimated future net revenue[(b)]	$ 3,687	$ 718	$ 4,405
Standardized measure[(b)(c)]			$ 4,379

Operating Division	Oil	Natural Gas	NGL	Oil Equivalent	Proved Reserves	Present Value
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)	%	($ millions)
Southern	363	3,045	131	1,001	59	$ 3,279
Northern	36	3,451	95	707	41	1,126
Total	399	6,496	226	1,708	100%	$ 4,405 [(b)]

(a) 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 noncontrolling interest holders.

(b) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of December 31, 2016. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2016. The prices used in our reserve reports were $42.75 per bbl of oil and $2.49 per mcf of natural gas, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2016. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue differs from the standardized measure only because the former does not include the effects of estimated future income tax expenses ($26 million as of December 31, 2016).

Management uses estimated future net revenue, which is calculated without deducting estimated future income tax expenses, and the present value thereof as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which are consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company.

(c) Additional information on the standardized measure is presented in *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report.

As of December 31, 2016, our proved reserve estimates included 519 mmboe of reserves classified as proved undeveloped, compared to 242 mmboe as of December 31, 2015. Presented below is a summary of changes in our proved undeveloped reserves (PUDs) for 2016.

	Total (mmboe)
Proved undeveloped reserves, beginning of period	242
Extensions and discoveries	477
Revisions of previous estimates	(78)
Developed	(118)
Sale of reserves-in-place	(4)
Purchase of reserves-in-place	—
Proved undeveloped reserves, end of period	519

As of December 31, 2016, there were no PUDs that had remained undeveloped for five years or more. In 2016, we invested approximately $312 million to convert 118 mmboe of PUDs to proved developed reserves. In 2017, we estimate that we will invest approximately $606 million for PUD conversion. The downward revisions of 78 mmboe of PUDs in 2016 were related to a 34 mmboe reduction due to lower commodity prices and a 44 mmboe reduction resulting primarily from removing PUDs where it was determined development would occur outside of the five year development plan. Our proved undeveloped extensions and discoveries included 477 mmboe of reserves that resulted from improved drilling and operating efficiencies, including the impact from extended laterals.

The future net revenue attributable to our estimated PUDs of $3.0 billion as of December 31, 2016, and the $718 million present value thereof, have been calculated assuming that we will expend approximately $2.9 billion to develop these reserves ($606 million in 2017, $550 million in 2018, $1.086 billion in 2019, $527 million in 2020 and $94 million in 2021), although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, commodity prices and the availability of capital. Chesapeake's developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as unexpected developmental drilling results, title issues and infrastructure availability or constraints.

Our annual net decline rate on current proved producing properties is projected to be 31% in 2017, 22% in 2018, 17% in 2019, 14% in 2020 and 12% in 2021. Of our 1.189 bboe of proved developed reserves as of December 31, 2016, approximately 126 mmboe, or 11%, were non-producing.

Chesapeake's ownership interest used for calculating proved reserves and the associated estimated future net revenue assumes maximum participation by other parties to our farm-out and participation agreements. SEC pricing used for calculating the estimated future net revenue attributable to our proved reserves does not reflect actual market prices for oil and natural gas production sold subsequent to December 31, 2016.

The Company's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2016, 2015 and 2014, along with the changes in quantities and standardized measure of the reserves for each of the three years then ended, are shown in *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of these estimates, and these revisions may be material. Accordingly, reserve estimates often differ from the actual quantities of oil, natural gas and NGL that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate.

Reserves Estimation

Chesapeake's Corporate Reserves Department prepared approximately 30% by volume, and approximately 17% by value, of our estimated proved reserves disclosed in this report. Those estimates were based upon the best available production, engineering and geologic data.

Chesapeake's Director – Corporate Reserves, is the technical person primarily responsible for overseeing the preparation of the Company's reserve estimates. His qualifications include the following:

- 26 years of practical experience working for major oil companies, including 18 years in reservoir engineering responsible for estimation and evaluation of reserves;
- Bachelor of Science degree in Petroleum Engineering;
- registered professional engineer in the state of Texas; and
- member in good standing of the Society of Petroleum Engineers.

We ensure that the key members of our Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserves estimates. Each of our Corporate Reserves Advisors has more than 30 years of engineering experience in reserve estimation. Our engineering technicians have a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field. We maintain a continuous education program for our engineers and technicians on new technologies and industry advancements as well as refresher training on basic skills and analytical techniques.

We maintain internal controls such as the following to ensure the reliability of reserves estimations:

- We follow comprehensive SEC-compliant internal policies to estimate and report proved reserves. Reserve estimates are made by experienced reservoir engineers or under their direct supervision. All material changes are reviewed and approved by Corporate Reserves Advisors.
- The Corporate Reserves Department reviews the Company's proved reserves at the close of each quarter.
- Each quarter, Corporate Reserves Department managers, the Director – Corporate Reserves, the Vice Presidents of our business units, the Director of Corporate and Strategic Planning and the Executive Vice President – Exploration and Production review all significant reserves changes and all new proved undeveloped reserves additions.
- The Corporate Reserves Department reports independently of our operating divisions.
- The five year PUD development plan is reviewed and approved annually by the Director of Corporate Reserves and the Director of Corporate and Strategic Planning.

We engaged Software Integrated Solutions, Division of Schlumberger Technology Corporation, a third-party engineering firm, to prepare approximately 70% by volume, and approximately 83% by value, of our estimated proved reserves as of December 31, 2016. A copy of the report issued by the engineering firm is filed with this report as Exhibits 99.1. The qualifications of the technical person at the firm primarily responsible for overseeing the preparation of the Company's reserve estimates are set forth below.

- over 30 years of practical experience in the estimation and evaluation of reserves;
- registered professional geologist license in the Commonwealth of Pennsylvania;
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and
- Bachelor of Science degree in Geological Sciences.

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

The following table sets forth historical costs incurred in oil and natural gas property acquisition, exploration and development activities during the periods indicated:

	Years Ended December 31, 2016	2015	2014
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ 403	$ —	$ 214
Unproved properties	403	454	1,224
Exploratory costs	52	112	421
Development costs	1,312	2,941	4,204
Costs incurred[(a)(b)]	$ 2,170	$ 3,507	$ 6,063

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $51 million and $679 million in 2015 and 2014, respectively.

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

	2016	2015	2014
Capitalized interest	$ 242	$ 410	$ 604
Asset retirement obligations	$ (57)	$ (15)	$ 39

A summary of our exploration and development, acquisition and divestiture activities in 2016 by operating division is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties	Acquisition of Proved Properties	Sales of Unproved Properties	Sales of Proved Properties[(a)]	Total[(b)]
			($ in millions)					
Southern	375	212	$ 1,169	$ 252	$ 277	$ (432)	$ (849)	$ 417
Northern	60	27	195	151	126	(19)	(258)	195
Total	435	239	$ 1,364	$ 403	$ 403	$ (451)	$ (1,107)	$ 612

(a) Includes asset retirement disposal of $179 million related to divestitures.

(b) Includes capitalized internal costs of $148 million and related capitalized interest of $242 million.

Acreage

The following table sets forth our gross and net developed and undeveloped oil and natural gas leasehold and fee mineral acreage as of December 31, 2016. "Gross" acres are the total number of acres in which we own a working interest. "Net" acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our unexercised options to acquire additional acreage.

	Developed Leasehold		Undeveloped Leasehold		Fee Minerals		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)							
Southern	3,776	1,871	996	427	152	35	4,924	2,333
Northern	1,848	1,380	3,482	2,087	708	457	6,038	3,924
Total	5,624	3,251	4,478	2,514	860	492	10,962	6,257

Most of our leases have a three- to five-year primary term, and we manage lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling our drilling to establish production in paying quantities in order to hold leases by production, timely exercising our contractual rights to pay delay rentals to extend the terms of leases we value, planning noncore divestitures to high-grade our lease inventory and letting some leases expire that are no longer part of our development plans. The following table sets forth the expiration periods of gross and net undeveloped leasehold acres as of December 31, 2016.

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2017	1,126	660
2018	462	192
2019	243	157
After 2019	2,647	1,505
Total[a]	4,478	2,514

(a) Includes 2.5 million gross (1.4 million net) held-by-production acres that will remain in force as production continues on the subject leases, and other leasehold acreage where management anticipates the lease to remain in effect past the primary term of the agreement due to our contractual option to extend the lease term.

Marketing, Gathering and Compression

Our marketing activities, along with our midstream gathering and compression operations, constitute a reportable segment under accounting guidance for disclosure about segments of an enterprise and related information. See Note 21 of the notes to our consolidated financial statements included in Item 8 of Part II of this report.

Marketing

Chesapeake Energy Marketing, L.L.C., one of our wholly owned subsidiaries, provides oil, natural gas and NGL marketing services, including commodity price structuring, securing and negotiating gathering, hauling, processing and transportation services, contract administration and nomination services for Chesapeake and other interest owners in Chesapeake-operated wells. We also perform marketing services for third-party producers in wells in which we do not have an interest. We attempt to enhance the value of oil and natural gas production by aggregating volumes to be sold to various intermediary markets, end markets and pipelines. This aggregation allows us to attract larger, more creditworthy customers that in turn assist in maximizing the prices received. In addition, we periodically enter into a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including credit risk mitigation and to help meet certain of our pipeline delivery commitments.

Oil production is generally sold under market-sensitive short-term or spot price contracts. Natural gas and NGL production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received from the ultimate purchaser. Under percentage-of-index contracts, the price we receive is tied to published indices. Sales to BP PLC constituted approximately 10% and 14% of our total revenues (before the effects of hedging) for the years ended December 31, 2016 and 2015, respectively. Sales to Exxon Mobil Corporation constituted approximately 12% of our total revenues (before the effects of hedging) for the year ended December 31, 2014.

Midstream Gathering Operations

Historically, we invested, directly and through affiliates, in gathering systems and processing facilities to complement our natural gas operations in regions where we had significant production and additional infrastructure was required. These systems were designed primarily to gather our production for delivery into major intrastate or interstate pipelines. In addition, our midstream business provided services to joint working interest owners and other third-party customers. We generated revenues from our gathering, treating and compression activities through various gathering rate structures. As of December 31, 2016, we sold substantially all of our remaining assets associated with our natural gas gathering business.

Compression Operations

Since 2003, we have operated our compression business through our wholly owned subsidiaries, Compass Manufacturing, L.L.C. (Compass) and MidCon Compression, L.L.C. (MidCon). Compass designs, engineers, fabricates, installs and sells natural gas compression units, accessories and equipment used in the production, treatment and processing of oil and natural gas. A majority of the completed compressors are sold to MidCon. MidCon operates wellhead and system compressors, with approximately 150,000 horsepower of compression, to facilitate the transportation of natural gas primarily produced from Chesapeake-operated wells.

Spin-Off of Oilfield Services Business

On June 30, 2014, we completed the spin-off of our oilfield services business, which we previously conducted through our indirect, wholly owned subsidiary Chesapeake Oilfield Operating, L.L.C. (COO), into an independent, publicly traded company called Seventy Seven Energy Inc. (SSE). See Note 13 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for additional information regarding the spin-off.

Following the spin-off, we have no ownership interest in SSE. Therefore, we ceased to consolidate SSE's assets and liabilities as of the spin-off date. Because we expect to have significant continued involvement associated with SSE's future operations through the various agreements we entered into in connection with the spin-off, our former oilfield services segment's historical financial results for periods prior to the spin-off continue to be included in our historical financial results as a component of continuing operations.

Competition

We compete with both major integrated and other independent oil and natural gas companies in all aspects of our business to explore, develop and operate our properties and market our production. Some of our competitors may have larger financial and other resources than ours. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of our competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of natural gas pipelines and other transportation facilities and overall economic conditions. We also face indirect competition from alternative energy sources, including wind, solar and electric power. We believe that our technological expertise, our exploration, land, drilling and production capabilities and the experience of our management generally enable us to compete effectively.

Regulation – General

All of our operations are conducted onshore in the United States. The U.S. oil and natural gas industry is regulated at the federal, state and local levels, and some of the laws and regulations that govern our operations carry substantial administrative, civil and criminal penalties for non-compliance. Although we believe we are in material compliance with all applicable laws and regulations, and that the cost of compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations could be, and frequently are, amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance or non-compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, local governments, the courts and federal agencies, such as the U.S. Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission (FERC), the Department of Transportation (DOT), the Department of Interior (DOI) and the U.S. Army Corps of Engineers (USACE). We actively monitor regulatory developments applicable to our industry in order to anticipate, design and implement required compliance activities and systems.

Exploration and Production Operations

The laws and regulations applicable to our exploration and production operations include requirements for permits or approvals to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to such laws and regulations include, but are not limited to, the following:

- seismic operations;
- the location of wells;
- construction and operations activities, including in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- the method of drilling and completing wells;
- production operations, including the installation of flowlines and gathering systems;
- air emissions and hydraulic fracturing;
- the surface use and restoration of properties upon which oil and natural gas facilities are located, including the construction of well pads, pipelines, impoundments and associated access roads;

- water withdrawal;
- the plugging and abandoning of wells;
- the generation, storage, transportation treatment, recycling or disposal of hazardous waste, fluids or other substances in connection with operations;
- the construction and operation of underground injection wells to dispose of produced water and other liquid oilfield wastes;
- the construction and operation of surface pits to contain drilling muds and other fluids associated with drilling operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit our ability to execute our drilling and production plans. Failure to comply with applicable regulations or permit requirements could result in revocation of our permits, inability to obtain new permits and the imposition of fines and penalties.

Our exploration and production activities are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells that may be drilled in a particular area) and the unitization or pooling of oil and natural gas properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas, West Virginia and Pennsylvania, rely on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units and, therefore, more difficult to fully develop a project if the operator owns or controls less than 100% of the leasehold. In addition, some states' conservation laws establish maximum rates of production from oil and natural gas wells, generally limit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of oil and natural gas we can produce and to limit the number of wells and the locations at which we can drill.

Hydraulic Fracturing

Hydraulic fracturing is typically regulated by state oil and gas regulatory authorities, including specifically the requirement to disclose certain information related to hydraulic fracturing operations. We follow applicable legal requirements for groundwater protection in our operations that are subject to supervision by state and federal regulators (including the BLM on federal acreage). Furthermore, our well construction practices require the installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers. Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies continue to assess the impacts of hydraulic fracturing that could spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities. In addition, in light of concerns about seismic activity being triggered by the injection of produced waters into underground wells and hydraulic fracturing, certain regulators are also considering additional requirements related to seismic safety for hydraulic fracturing activities. Further restrictions on hydraulic fracturing could make it prohibitive to conduct our operations, and also reduce the amount of oil, natural gas and NGL that we are ultimately able to produce in commercial quantities from our properties. For further discussion, see Item *1A. Risk Factors – Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.*

Midstream Operations

Historically, Chesapeake invested, directly and through an affiliate, in gathering systems and processing facilities to complement our natural gas operations in regions where we had significant production and additional infrastructure was required. In 2012 and 2013, we sold a significant portion of our midstream business, including most of our gathering assets. As of December 31, 2016, we sold substantially all of our remaining assets associated with our natural gas gathering business. As a result, the impact on our business of compliance with the laws and regulations described below has decreased significantly since the fourth quarter of 2012.

In addition to the environmental, health and safety laws and regulations discussed below under *Regulation – Environment, Health and Safety Matters*, a small number of our midstream facilities are subject to federal regulation by the Pipeline and Hazardous Materials Safety Administration of the DOT pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA) and the Pipeline Safety Improvement Act of 2002, which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and reauthorized and amended again by the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their assertion of authority and capacity to address pipeline safety. We have inspection and compliance programs designed to keep our natural gas pipeline facilities in compliance with current pipeline safety and pollution control laws and regulations. However, future PHMSA rulemakings could have a material impact on our operations.

Natural gas gathering and intrastate transportation facilities are exempt from the jurisdiction of the FERC under the Natural Gas Act. Although the FERC has made no formal determinations with regard to any of our facilities, we believe that our natural gas pipelines and related facilities are engaged in exempt gathering and intrastate transportation and, therefore, are not subject to the FERC's jurisdiction. Nevertheless, FERC regulation affects our gathering and compression business, generally, in that some of our assets feed into FERC-regulated systems. FERC provides policies and practices across a range of natural gas regulatory activities, including, for example, its policies on open access transportation, market manipulation, ratemaking, capacity release and market transparency, and market center promotion, which indirectly affect our gathering and compression business. In addition, the distinction between FERC-regulated transmission facilities and federally unregulated gathering and intrastate transportation facilities is a fact-based determination made by the FERC on a case-by-case basis; this distinction has also been the subject of regular litigation and change. The classification and regulation of our gathering and intrastate transportation facilities are subject to change based on future determinations by the FERC, the courts and Congress.

Our natural gas gathering operations are subject to ratable-take and common-purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate typically have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination.

Regulation – Environment, Health and Safety

Our operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of human health and safety, the environment and natural resources. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we can handle or dispose of wastes and other substances associated with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species and/or species of special statewide concern or their habitats;
- requiring investigatory and remedial actions to address pollution caused by our operations or attributable to former operations;
- requiring noise, lighting, visual impact, odor and/or dust mitigation, setbacks, landscaping, fencing, and other measures;
- restricting access to certain equipment or areas to a limited set of employees or contractors who have proper certification or permits to conduct work (e.g., confined space entry and process safety maintenance requirements); and
- restricting or even prohibiting water use based upon availability, impacts or other factors.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial or restoration obligations, and the issuance of orders enjoining future operations or imposing additional compliance requirements. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, local restrictions, such as state or local moratoria, city ordinances, zoning laws and traffic regulations, may restrict or prohibit the execution of our drilling and production plans. In addition, third parties, such as neighboring landowners, may file claims alleging property damage, nuisance or personal injury arising from our operations or from the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. We monitor developments at the federal, state and local levels to inform our actions pertaining to future regulatory requirements that might be imposed to mitigate the costs of compliance with any such requirements. We also participate in industry groups that help formulate recommendations for addressing existing or future regulations and that share best practices and lessons learned in relation to pollution prevention and incident investigations.

Below is a discussion of the major environmental, health and safety laws and regulations that relate to our business. We believe that we are in material compliance with these laws and regulations. We do not believe that compliance with existing environmental, health and safety laws or regulations will have a material adverse effect on our financial condition, results of operations or cash flow. At this point, however, we cannot reasonably predict what applicable laws, regulations or guidance may eventually be adopted with respect to our operations or the ultimate cost to comply with such requirements.

Hazardous Substances and Waste

Federal and state laws, in particular the federal Resource Conservation and Recovery Act (RCRA) regulate hazardous and non-hazardous wastes. In the course of our operations, we generate petroleum hydrocarbon wastes, such as drill cuttings, produced water and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, although they are regulated under other federal and state waste laws. At various times in the past, most recently in December 2016, proposals have been made to amend RCRA or otherwise eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose and would cause us, as well as our competitors, to incur significantly increased operating expenses.

Federal, state and local laws may also require us to remove or remediate wastes or hazardous substances that have been previously disposed or released into the environment. This can include removing or remediating wastes or hazardous substances disposed or released by us (or prior owners or operators) in accordance with then current laws, suspending or ceasing operations at contaminated areas, or performing remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered legally responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, persons who disposed or arranged for the disposal of hazardous substances at the site, and any person who accepted hazardous substances for transportation to the site. CERCLA and analogous state laws also authorize the EPA, state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and/or seek recovery of the costs of such actions from responsible classes of persons.

The Underground Injection Control (UIC) Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. Chesapeake recycles and reuses some produced water and we also dispose of produced water in Class II UIC wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. Permits for Class II UIC wells may be issued by the EPA or by a state regulatory agency if EPA has delegated its UIC Program authority. Because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal.

Air Emissions

Our operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. Among other things, these laws and regulations regulate emissions of air pollutants from various industrial sources, including compressor stations and production equipment, and impose various control, monitoring and reporting requirements. Permits and related compliance obligations under the CAA, each state's development and promulgation of regulatory programs to comport with federal requirements, as well as changes to state implementation plans for controlling air emissions in regional non-attainment or near-non-attainment areas, may require oil and gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

Discharges into Waters

The federal Water Pollution Control Act, or the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. Spill prevention, control and countermeasure regulations require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities and construction activities.

The Oil Pollution Act of 1990 (OPA) establishes strict liability for owners and operators of facilities that release oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the United States.

Health and Safety

The Occupational Safety and Health Act (OSHA) and comparable state laws regulate the protection of the health and safety of our employees. The federal Occupational Safety and Health Administration has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. OSHA also requires employee training and maintenance of records, and the OSHA hazard communication standard and EPA community right-to-know regulations under the Emergency Planning and Community Right-to-Know Act of 1986 require that we organize and/or disclose information about hazardous materials used or produced in our operations.

Endangered Species

The Endangered Species Act (ESA) prohibits the taking of endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity or the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

Global Warming and Climate Change

At the federal level, EPA regulations require us to establish and report an inventory of greenhouse gas emissions. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the oil and natural gas that we sell. The EPA recently finalized new standards of performance limiting methane emissions from oil and gas sources. The potential increase in our operating costs could include new or increased costs to (i) obtain permits, (ii) operate and maintain our equipment and facilities (through the reduction or elimination of venting and flaring of methane), (iii) install new emission controls on our equipment and facilities, (iv) acquire allowances authorizing our greenhouse gas emissions, (v) pay taxes related to our greenhouse gas emissions and (vi) administer and manage a greenhouse gas emissions program. In addition to these federal actions, various state governments and/or regional agencies may consider enacting new legislation and/or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations.

In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and “represent a progression” in their nationally determined contributions, which set emissions reduction goals, every five years. For further discussion, see Item *1A. Risk Factors - Potential legislative and regulatory actions addressing climate change could significantly impact our industry and the Company, causing increased costs and reduced demand for oil and natural gas.*

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil and natural gas industry, to liens for current taxes not yet due and to other encumbrances. As is customary in the industry in the case of undeveloped properties, only cursory investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Nevertheless, we are involved in title disputes from time to time which result in litigation.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, Chesapeake could incur legal defense costs and could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

Chesapeake maintains a control of well policy with a $50 million single well limit and a $100 million multiple wells limit that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. Chesapeake also carries a $250 million comprehensive general liability umbrella policy. In addition, Chesapeake maintains a $150 million pollution liability policy providing coverage for gradual pollution related risks and in excess of the general liability policy for sudden and accidental pollution risks. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks, and policy limits scale to Chesapeake’s working interest percentage in certain situations. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. Our insurance coverage may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

Facilities

Chesapeake owns an office complex in Oklahoma City and owns or leases various field offices in cities or towns in the areas where we conduct our operations.

Executive Officers

Robert D. Lawler, *President, Chief Executive Officer and Director*

Robert D. ("Doug") Lawler, 50, has served as President and Chief Executive Officer since June 2013. Prior to joining Chesapeake, Mr. Lawler served in multiple engineering and leadership positions at Anadarko Petroleum Corporation. His positions at Anadarko included Senior Vice President, International and Deepwater Operations and member of Anadarko's Executive Committee from July 2012 to May 2013; Vice President, International Operations from December 2011 to July 2012; Vice President, Operations for the Southern and Appalachia Region from March 2009 to July 2012; and Vice President, Corporate Planning from August 2008 to March 2009. Mr. Lawler began his career with Kerr-McGee Corporation in 1988 and joined Anadarko following its acquisition of Kerr-McGee in 2006.

Domenic J. Dell'Osso, Jr., *Executive Vice President and Chief Financial Officer*

Domenic J. ("Nick") Dell'Osso, Jr., 40, has served as Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso served as Vice President – Finance of the Company and Chief Financial Officer of Chesapeake's wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., from August 2008 to November 2010.

Frank Patterson, *Executive Vice President – Exploration and Production*

Frank Patterson, 58, has served as Executive Vice President - Exploration and Production since August 2016. Previously, he served as Executive Vice President – Exploration and Northern Division since April 2016 and as Executive Vice President – Exploration, Technology & Land since May 2015. Before joining Chesapeake, Mr. Patterson served in various roles at Anadarko from 2006 to 2015, most recently as Senior Vice President – International Exploration. Prior to that he was Vice President – Deepwater Exploration at Kerr-McGee and Manager – Geology at Sun E&P/Oryx Energy.

Mikell J. Pigott, *Executive Vice President – Operations and Technical Services*

Mikell J. ("Jason") Pigott, 43, has served as Executive Vice President – Operations and Technical Services since August 2016. Previously, he served as Executive Vice President – Operations, Southern Division since January 2015 and Senior Vice President – Operations, Southern Division since August 2013. Before joining Chesapeake, Mr. Pigott served in various positions at Anadarko and focused on all aspects of developing unconventional resources. His positions at Anadarko included General Manager Eagle Ford from June to August 2013; General Manager East Texas and North Louisiana from October 2010 to June 2013; Southern & Appalachia Planning Manager from October 2009 to October 2010; Reservoir Engineering Manager East Texas and North Louisiana from July to October 2009; and Reservoir Engineering Manager Bossier from 2007 to July 2009.

James R. Webb, *Executive Vice President – General Counsel and Corporate Secretary*

James R. Webb, 49, has served as Executive Vice President – General Counsel and Corporate Secretary since January 2014. Previously, he served as Senior Vice President – Legal and General Counsel since October 2012 and as Corporate Secretary since August 2013. Mr. Webb first joined Chesapeake in May 2012 on a contract basis as Chief Legal Counsel. Prior to joining Chesapeake, Mr. Webb was an attorney with the law firm of McAfee & Taft from 1995 to October 2012.

Michael A. Johnson, *Senior Vice President – Accounting, Controller and Chief Accounting Officer*

Michael A. Johnson, 51, has served as Senior Vice President – Accounting, Controller and Chief Accounting Officer since 2000. He served as Vice President of Accounting and Financial Reporting from 1998 to 2000 and as Assistant Controller from 1993 to 1998.

Other Senior Officer

Cathlyn L. Tompkins, *Senior Vice President – Information Technology and Chief Information Office*r

Cathlyn L. Tompkins, 56, has served as Senior Vice President – Information Technology and Chief Information Officer since 2006. Ms. Tompkins served as Vice President – Information Technology from 2005 to 2006.

Employees

Chesapeake had approximately 3,300 employees as of December 31, 2016.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this report.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bboe. One billion barrels of oil equivalent.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

Bbtu. One billion British thermal units.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Boe. Barrel of oil equivalent.

Commercial Well; Commercially Productive Well. A well which produces oil, natural gas and/or NGL in sufficient quantities such that proceeds from the sale of this production exceeds production expenses and taxes.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil, natural gas or NGL, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Drilling Carry Obligation. An obligation of one party to pay certain well costs attributable to another party.

Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Exploratory Well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Full Cost Pool. The full cost pool consists of all costs associated with property acquisition, exploration and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which a working interest is owned.

Mboe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

Mmboe. One million barrels of oil equivalent.

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Natural Gas Liquids (NGL). Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include ethane, propane, butane, isobutene, pentane, hexane and natural gasoline.

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Play. A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil, natural gas and NGL reserves.

Present Value or PV-10. When used with respect to oil, natural gas and NGL reserves, present value, or PV-10, means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average oil and natural gas price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Price Differential. The difference in the price of oil, natural gas or NGL received at the sales point and the NYMEX price.

Productive Well. A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved Developed Reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved Properties. Properties with proved reserves.

Proved Reserves. Proved oil and natural gas reserves are those quantities of oil and natural gas, 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of a 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 (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated 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 that 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is 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.

Proved Undeveloped Reserves (PUDs). Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively high expenditure compared to the cost of drilling a new well is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless these techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Realized and Unrealized Gains and Losses on Oil, Natural Gas and NGL Derivatives. Realized gains and losses includes the following items:(i) settlements and accruals for settlements of non-designated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period production revenues, and (iii) gains and losses related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains and losses include the change in fair value of open derivatives scheduled to settle against future period production revenues (including current period settlements for option premiums and early-terminated derivatives) offset by amounts reclassified as realized gains and losses during the period. Although we no longer designate our derivatives as cash flow hedges for accounting purposes, we believe these definitions are useful to management and investors in determining the effectiveness of our price risk management program.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty Interest. An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas or NGL production free of costs of production.

Seismic. An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures).

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on the prices used in estimating the proved reserves, year-end costs and statutory tax rates (adjusted for permanent differences) and a 10% annual discount rate.

Tbtu. One trillion British thermal units.

Undeveloped Acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether the acreage contains proved reserves.

Unproved Properties. Properties with no proved reserves.

Volumetric Production Payment (VPP). As we use the term, a volumetric production payment represents a limited-term overriding royalty interest in oil and natural gas reserves that: (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain the remaining reserves, if any, after the scheduled production volumes have been delivered.

Working Interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

ITEM 1A. *Risk Factors*

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a description of significant factors that might cause our future results to differ materially from those currently expected. The risks described below are not the only risks facing our company. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also affect our business operations. If any of these risks actually occur, our business, financial position, operating results, cash flows, reserves and/or our ability to pay our debts and other liabilities could suffer, the trading price and liquidity of our securities could decline and you may lose all or part of your investment in our securities.

Oil, natural gas and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.

Our revenues, operating results, profitability, liquidity and ability to grow depend primarily upon the prices we receive for the oil, natural gas and NGL we sell. We require substantial expenditures to replace reserves, sustain production and fund our business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures and debt repayment and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves. In addition, low prices may result in ceiling test write-downs of our oil and natural gas properties. We urge you to read the risk factors below for a more detailed description of each of these risks.

Historically, the markets for oil, natural gas and NGL have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil, natural gas and NGL prices may result from relatively minor changes in the supply of or demand for oil, natural gas and NGL, market uncertainty and other factors that are beyond our control, including:

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- weather conditions;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;
- the effectiveness of worldwide conservation measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- U.S. exports of oil and/or liquefied natural gas;
- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil and natural gas producing regions;
- acts of terrorism; and
- domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. Oil and natural gas prices remained low throughout 2016 and into the first quarter of 2017. As of February 24, 2017, 68% and 71% of our forecasted 2017 oil production and natural gas production, respectively, was hedged under swaps and collars. Even with oil and natural gas derivatives currently in place to mitigate price risks associated with a portion of our 2017 production, we have substantial exposure to oil, natural gas and NGL prices in 2018 and beyond. In addition, a prolonged extension of lower prices could reduce the quantities of reserves that may be economically produced.

We have a significant amount of indebtedness. Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects, and we may have difficulty paying our debts as they become due.

As of December 31, 2016, we had approximately $10.0 billion in principal amount of debt (including current maturities), and borrowing capacity of approximately $2.8 billion under our $4.0 billion senior secured revolving credit facility, which was undrawn (other than letters of credit issued thereunder in the aggregate amount of $1.0 billion). We also had a net working capital deficit of approximately $1.506 billion as of December 31, 2016. During January 2017, we repurchased or retired approximately $900 million principal amount of debt, resulting in a debt balance of $9.1 billion principal amount as of February 24, 2017.

The level of and terms and conditions governing our debt:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt obligations and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to economic downturns or adverse developments in our business;
- could limit our ability to access the capital markets to refinance our existing indebtedness, to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures, acquisitions, debt service requirements or execution of our business strategy or for other purposes;
- expose us to the risk of increased interest rates as certain of our borrowings, including borrowings under our credit facility, bear interest at floating rates;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or that have less restrictive terms governing their indebtedness and, therefore, that may be able to take advantage of opportunities that our indebtedness prevents us from pursuing;
- limit management's discretion in operating our business; and
- increase our cost of borrowing.

Any of the above listed factors could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. We have previously drawn on our credit facility for liquidity, and the borrowing base under our credit facility is subject to redetermination on June 15, 2017. To the extent that the value of the collateral pledged under the credit facility declines as a result of lower oil and natural gas prices, asset dispositions or otherwise, we may be required to pledge additional collateral in order to maintain the current availability of the commitments thereunder, and we cannot assure you that we will be able to maintain a sufficiently high valuation to maintain the current commitments. Our borrowing base may be reduced if we dispose of a certain percentage of the value of the collateral securing our facility. As a result of certain asset sales in 2016, our borrowing base was reduced to $3.8 billion. In addition, we cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we are unable to service our indebtedness and other obligations, we may be required to restructure or refinance all or part of our existing debt, sell assets, reduce capital expenditures, borrow more money or raise equity. We may not be able to restructure or refinance our debt, reduce capital expenditures, sell assets, borrow more money or raise equity on terms acceptable to us, if at all, or such alternative strategies may yield insufficient funds to make required payments on our indebtedness. In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness is uncertain and will be affected by our future performance and events or circumstances beyond our control. Failure to comply with these covenants would result in an event of default under such indebtedness, the potential acceleration of our obligation to repay outstanding debt and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under our other outstanding indebtedness. Any of the above risks could materially adversely affect our business, financial condition, cash flows and results of operations.

We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by our debt level and industry conditions.

Disruptions in the capital and credit markets, in particular with respect to companies in the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Low commodity prices during 2015 and 2016, among other factors, caused and may continue to cause lenders to increase interest rates, enact tighter lending standards which we may not satisfy as a result of our debt level or otherwise, refuse to refinance existing debt around maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, it could materially adversely affect our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operations and service our debt. Factors that may cause us to generate cash flow that is insufficient to meet our debt obligations include the events and risks related to our business, many of which are beyond our control. Any cash flow insufficiency would materially adversely impact our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

If we are unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

We cannot assure you that our business will generate sufficient cash flow from operations to service our outstanding indebtedness, or that future borrowings will be available to us in an amount sufficient to enable us to pay or refinance our indebtedness, manage our working capital or fund our other capital needs. As a result, we may be required to undertake various alternative financing plans, which may include:

- refinancing or restructuring all or a portion of our debt;
- obtaining alternative financing;
- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- revising or delaying our strategic plans.

However, we cannot assure you that we would be able to implement alternative financing plans, if necessary, on commercially reasonable terms or at all, or that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations and capital requirements or that these actions would be permitted under the terms of our various debt instruments. If we are unsuccessful in implementing any required alternative financing plans or otherwise improving our liquidity, we may not be able to fund budgeted capital expenditures or meet our debt service requirements.

If we are unable to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing, our business, financial condition, results of operations, cash flows and liquidity could be materially and adversely affected. Any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could significantly harm our ability to incur additional indebtedness on acceptable terms. Further, if for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors under those agreements to declare all outstanding indebtedness thereunder to be due and payable (which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements), the lenders under our credit facility could terminate their commitments to extend credit, and the lenders could foreclose against our assets securing their borrowings and we could be forced into bankruptcy or liquidation. In addition, the lenders under our credit facility could compel us to apply our available cash to repay our borrowings. If the amounts outstanding under the credit facility or any of our other significant indebtedness were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our credit facility, term loan facility and floating rate senior notes due 2019 bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

Restrictive covenants in certain of our debt agreements could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Certain of our debt agreements impose operating and financial restrictions on us. These restrictions limit our ability and that of our restricted subsidiaries to, among other things:

- incur additional indebtedness;
- make investments or loans;
- create liens;
- consummate mergers and similar fundamental changes;
- make restricted payments;
- make investments in unrestricted subsidiaries;
- enter into transactions with affiliates; and
- use the proceeds of asset sales.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under certain of our debt agreements. The restrictions contained in the covenants could:

- limit our ability to plan for, or react to, market conditions, to meet capital needs or otherwise to restrict our activities or business plan; and
- adversely affect our ability to finance our operations, enter into acquisitions or to engage in other business activities that would be in our interest.

Also, our credit facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a continued downturn in our business or a downturn in the economy in general or otherwise conduct necessary corporate activities. Declines in oil, NGL and natural gas prices, or a prolonged period of low oil, NGL and natural gas prices, could eventually result in our failing to meet one or more of the financial covenants under our credit facility, which could require us to refinance or amend such obligations resulting in the payment of consent fees or higher interest rates, or require us to raise additional capital at an inopportune time or on terms not favorable to us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit facility. A default under our credit facility, if not cured or waived, could result in acceleration of all indebtedness outstanding thereunder. The accelerated debt would become immediately due and payable, which would in turn trigger cross-acceleration and cross-default rights under our other debt. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. In addition, in the event of an event of default under the credit facility, term loan or second lien notes, the affected lenders could foreclose on the collateral securing the credit facility and require repayment of all borrowings outstanding thereunder. If the amounts outstanding under the credit facility or any of our other indebtedness were to be accelerated, our assets may not be sufficient to repay in full the money owed to the lenders or to our other debt holders. Moreover, any new indebtedness we incur may impose financial restrictions and other covenants on us that may be more restrictive than our existing debt agreements.

Our credit rating could negatively impact our availability and cost of capital and could require us to post more collateral under certain commercial arrangements.

Since December 2015, Moody's Investor Services, Inc. and Standard & Poor's Rating Services have significantly lowered our credit ratings. The downgrades were primarily a result of the effect of low oil and natural gas prices on our ability to generate cash flow from operations. We cannot provide assurance that our credit ratings will not be reduced if commodity prices decrease. Any downgrade to our credit ratings could negatively impact our availability and cost of capital.

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, transportation, processing and hedging agreements. As of February 24, 2017, we have received requests and posted approximately $275 million in collateral under such arrangements (excluding the supersedeas bond with respect to the 2019 Notes litigation discussed in Note 3 of the notes to our consolidated financial statements included in Item 8 of this report). We have posted the required collateral, primarily in the form of letters of credit and cash, or are otherwise complying with these contractual requests for collateral. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $451 million (excluding the supersedeas bond with respect to the 2019 Notes litigation), which may be in the form of additional letters of credit, cash or other acceptable collateral. Any posting of collateral consisting of cash or letters of credit, which would reduce availability under our credit facility, will negatively impact our liquidity.

Declines in commodity prices could result in write downs of the carrying value of our oil and natural gas properties.

Under the full cost method of accounting for costs related to our oil and natural gas properties, we are required to write down the carrying value of our oil and natural gas assets if capitalized costs exceed the quarterly ceiling limit, which is based on the average of commodity prices on the first day of the month over the trailing 12-month period. Such write-downs can be material. For example, for the year ended December 31, 2016, we reported non-cash impairment charges on our oil and natural gas properties totaling $2.564 billion, primarily resulting from a substantial decrease in the trailing 12-month average first-day-of-the-month oil and natural gas prices throughout 2016. The trailing 12-month average first-day-of-the-month prices used to calculate our oil and natural gas reserves decreased from $50.28 per bbl of oil and $2.58 per mcf of natural gas as of December 31, 2015 to $42.75 per bbl of oil and $2.49 per mcf of natural gas as of December 31, 2016. As of December 31, 2016, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $4.4 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of that date. Further material write-downs in subsequent quarters could occur if the trailing 12-month commodity prices fall as compared to the commodity prices used as of December 31, 2016.

Significant capital expenditures are required to replace our reserves and conduct our business.

Our exploration, development and acquisition activities require substantial capital expenditures. We intend to fund our capital expenditures through cash flows from operations, and to the extent that is not sufficient, cash on hand and borrowings under our revolving credit facility. Our ability to generate operating cash flow is subject to a number of risks and variables, such as the level of production from existing wells, prices of oil, natural gas and NGL, our success in developing and producing new reserves and the other risk factors discussed herein. If we are unable to fund our capital expenditures as planned, we could experience a curtailment of our exploration and development activity, a loss of properties and a decline in our oil, natural gas and NGL reserves.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. Our reserve estimates as of December 31, 2016, reflect an expected decline in the production rate on our producing properties of approximately 31% in 2017 and 22% in 2018. Thus, our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities of and future net revenues from our proved reserves may be less than our estimates.

The estimates of our proved reserves and the estimated future net revenues from our proved reserves included in this report are based upon various assumptions, including assumptions required by the SEC relating to oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil, natural gas and NGL reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to future revisions.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2016, approximately 30% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our PUDs into proved developed reserves, including approximately $2.9 billion during the five years ending in 2021. You should be aware that the estimated development costs may not equal our actual costs, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove them from our reported proved reserves. In addition, under the SEC's reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included in this report represent the current market value of our estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average oil and natural gas price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2016 present value is based on a $42.75 per bbl of oil price and a $2.49 per mcf of natural gas price, before considering basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. Any changes in consumption or in governmental regulations or taxation will also affect the actual future net cash flows from our production. In addition, the 10% discount factor which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have a substantial inventory of undeveloped properties. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We have acquired undeveloped properties that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that undeveloped properties acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such undeveloped properties or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling and completion operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, title problems, equipment failures or accidents, shortages of midstream transportation, equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and produced water disposal, and a decline in commodity prices, among others. The profitability of wells, particularly in certain of the areas in which we operate, will be reduced or eliminated as commodity prices decline. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for oil, natural gas and NGL, costs associated with producing oil, natural gas and NGL and our ability to add reserves at an acceptable cost. All costs of development and exploratory drilling activities are capitalized, even if the activities do not result in commercially productive discoveries, which may result in a future impairment of our oil and natural gas properties if commodity prices decrease.

We rely to a significant extent on seismic data and other advanced technologies in evaluating undeveloped properties and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of undeveloped properties, or drilling a well, whether oil or natural gas is present or may be produced economically. If we incur significant expense in acquiring or developing properties that do not produce as expected or at profitable levels, it could have a material adverse effect on our results of operations and financial condition.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases on our undeveloped properties expire and we are unable to renew the leases, we will lose our right to develop the related properties. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties.

Our commodity price risk management activities may limit the prices we receive for our oil, natural gas and NGL sales, require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

In order to manage our exposure to price volatility in marketing our production, we enter into oil and natural gas price derivative contracts for a portion of our expected production. Commodity price derivatives may limit the prices we actually realize for our oil, natural gas and NGL sales in the future. Our commodity price risk management activities will impact our earnings in various ways, including recognition of certain mark-to-market gains and losses on derivative instruments. The fair value of our oil and natural gas derivative instruments can fluctuate significantly between periods. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances.

Derivative transactions expose us to the risk that our counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. During periods of declining commodity prices, such as the period beginning in the fourth quarter of 2014 and continuing into the first half of 2016, the value of our commodity derivative asset positions increase, which increases our counterparty exposure. Although the counterparties to our hedging arrangements are required to secure their obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the derivative contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being exposed to commodity price changes.

Most of our oil, natural gas and NGL derivative contracts are with 10 counterparties under bi-lateral hedging arrangements. Under some of those arrangements, the counterparties' and our obligations under the bi-lateral hedging arrangements 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. Under certain circumstances, the cash collateral value posted could fall below the coverage designated, and we would be required to post additional cash or letter of credit collateral under our hedging arrangements. Under other arrangements, the collateral provided for our obligations under these arrangements are secured by hydrocarbon interests. Future collateral requirements are dependent to a great extent on oil and natural gas prices.

The ultimate outcome of pending legal and governmental proceedings is uncertain, and there are significant costs associated with these matters.

We are defending against claims by royalty owners alleging, among other things, that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sales of natural gas and NGL. Numerous cases, primarily in Texas, Pennsylvania and Ohio, are pending. The resolution of disputes regarding past payments could cause our future obligations to royalty owners to increase and would negatively impact our future results of operations.

In addition, there are ongoing governmental regulatory investigations and inquiries into such matters as our royalty practices, possible antitrust violations and our accounting methodology for the acquisition and classification of oil and natural gas properties. The outcome of any pending or future litigation or governmental regulatory matter is uncertain and may adversely affect our results of operations. In addition, we have incurred substantial legal expenses in the past three years, and such expenses may continue to be significant in the future. Further, attention to these matters by members of our senior management has been required, reducing the time they have available to devote to managing our business.

We may continue to incur cash and noncash charges that would negatively impact our future results of operations and liquidity.

While executing our strategic priorities to reduce financial leverage and complexity and to lower our capital expenditures in the face of lower commodity prices, we have incurred certain cash charges, including contract termination charges, restructuring and other termination costs, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. As we continue to focus on our strategic priorities, we may incur additional cash and noncash charges in 2017 and in future years. If incurred, these charges could materially adversely impact our future results of operations and liquidity.

Oil and natural gas drilling and producing operations can be hazardous and may expose us to liabilities.

Oil and natural gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, oil spills, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells or otherwise negatively impacting the projected economic performance of our prospects. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

A material event such as those described above could expose us to liabilities, monetary penalties or interruptions in our business operations. While we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. For certain risks, such as political risk, business interruption, war, terrorism and piracy, we have limited or no insurance coverage. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which we are not fully insured may expose us to liabilities.

We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner and feasibility of doing business, and further regulation in the future could increase costs, impose additional operating restrictions and cause delays.

Our operations and properties are subject to numerous federal, regional, state and local laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- conduct of our exploration, drilling, completion, production and midstream activities;
- amounts and types of emissions and discharges;
- generation, management, and disposition of hazardous substances and waste materials;
- reclamation and abandonment of wells and facility sites; and
- remediation of contaminated sites.

In addition, these laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations, including the assessment of administrative, civil and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. Future environmental laws and regulations imposing further restrictions on the emission of pollutants into the air, discharges into state or U.S. waters, wastewater disposal and hydraulic fracturing, or the designation of previously unprotected species as threatened or endangered in areas where we operate, may negatively impact our industry. We cannot predict the actions that future regulation will require or prohibit, but our business and operations could be subject to increased operating and compliance costs if certain regulatory proposals are adopted. In addition, such regulations may have an adverse impact on our ability to develop and produce our reserves.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Several states are considering adopting regulations that could impose more stringent permitting, public disclosure and/or well construction requirements on hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. There are also certain governmental reviews either underway or being proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. These studies assess, among other things, the risks of groundwater contamination and earthquakes caused by hydraulic fracturing and other exploration and production activities. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate or even ban such activities, as some state and local governments have already done. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Our ability to produce oil, natural gas and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Development activities require the use of water. For example, the hydraulic fracturing process that we employ to produce commercial quantities of oil and natural gas from many reservoirs requires the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. The imposition of new environmental initiatives and regulations, such as the Oklahoma Corporation Commission's (OCC) volume reduction plans for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation and the EPA's June 2016 pretreatment standards for wastewater, could further restrict our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of oil and natural gas.

Potential legislative and regulatory actions addressing climate change could significantly impact our industry and the Company, causing increased costs and reduced demand for oil and natural gas.

Various state governments and regional organizations have considered enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations. At the federal level, the EPA has already made findings and issued regulations that require us to establish and report an inventory of greenhouse gas emissions. Additional legislative and/or regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the oil and natural gas that we sell. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Even without federal legislation or regulation of greenhouse gas emissions, states may pursue the issue either directly or indirectly.

In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement will require countries to review and “represent a progression” in their nationally determined contributions, which set emissions reduction goals, every five years. The Paris Agreement could further drive regulation in the United States. Restrictions on emissions of methane or carbon dioxide that have been or may be imposed in various states, or at the federal level could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil and natural gas. Finally, we note that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The taxation of independent producers is subject to change, and federal and state proposals being considered could increase our cost of doing business.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation that could affect our tax burden could be enacted by any of these governmental authorities. Recently, legislative changes to impose additional taxes were proposed in Louisiana, Ohio, Oklahoma and Pennsylvania. Any of these proposals, if enacted, could make it more costly for us to explore for oil and natural gas resources.

Evolving OTC derivatives regulation could impact the effectiveness of our commodity hedging program.

In July 2010, the U.S. Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which contains measures aimed at migrating over-the-counter (OTC) derivative markets to exchange-traded and cleared markets. Certain companies that use derivatives to hedge commercial risk, referred to as end-users, are permitted to continue to use OTC derivatives under newly adopted regulations. We maintain an active price and basis risk management program related to the oil and natural gas we produce for our own account in order to manage the impact of low commodity prices and to predict future cash flows with greater certainty. We have used the OTC market exclusively for our oil and natural gas derivative contracts, and we have also used OTC derivatives to manage risks arising from interest rate exposure. The Dodd-Frank Act and the rules and regulations promulgated thereunder should permit us, as an end user, to continue to utilize OTC derivatives, but could cause increased costs and reduce liquidity in such markets. Such changes could materially reduce our hedging opportunities which would negatively affect our revenues and cash flow during periods of low commodity prices. New position limits rules proposed under the Dodd-Frank Act could also impact our commodity hedging program and could, if enacted as proposed, affect our ability to continue to use the full scope of OTC derivatives to hedge commodity price risk in the manner that we have in the past.

The oil and gas exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.

We face competition in every aspect of our business, including, but not limited to, buying and selling reserves and leases, obtaining goods and services needed to operate our business and marketing oil, natural gas or NGL. Competitors include multinational oil companies, independent production companies and individual producers and operators. Some of our competitors have greater financial and other resources than we do and, due to our debt levels and other factors, may have greater access to the capital and credit markets. As a result, these competitors may be able to address these competitive factors more effectively or weather industry downturns more easily than we can. We also face indirect competition from alternative energy sources, including wind, solar and electric power.

Our performance depends largely on the talents and efforts of highly skilled individuals and on our ability to attract new employees and to retain and motivate our existing employees. Competition in our industry for qualified employees is intense. If we are unsuccessful in attracting and retaining skilled employees and managerial talent, our ability to compete effectively will be diminished.

A deterioration in general economic, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.

In recent years, concerns about global economic growth have had a significant impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and materially adversely impact our results of operations, liquidity and financial condition.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, and explosions of natural gas transmission lines may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. For the year ended December 31, 2016, we did not operate approximately 7% of our daily production volumes. We have limited ability to influence or control the operation or future development of these non-operated properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Our operations may be adversely affected by pipeline and gathering system capacity constraints.

In certain shale plays, the capacity of gathering systems and transportation pipelines is insufficient to accommodate potential production from existing and new wells. We rely heavily on third parties to meet our oil, natural gas and NGL gathering needs. Capital constraints could limit the construction of new pipelines and gathering systems by third parties. Until this new capacity is available, we may experience delays in producing and selling our oil, natural gas and NGL. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell oil, natural gas or NGL production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

A portion of our oil, natural gas and NGL production may be subject to interruptions that could adversely affect our cash flow.

A portion of our oil, natural gas and NGL production in any region may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could materially adversely affect our cash flow.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. We have been the subject of cyber-attacks on our internal systems and through those of third parties, but these incidents did not have a material adverse impact on our results of operations. Nevertheless, unauthorized access to our seismic data, reserves information or other proprietary or commercially sensitive information could lead to data corruption, communication interruption, or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our results of operations. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks.

In connection with SSE's recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code, our spin-off of SSE may be challenged by SSE's former creditors.

In June 2014, we completed the spin-off of our oilfield services business into Seventy Seven Energy Inc. ("SSE"), an independent, publicly traded company. The substantial decline in oil and natural gas prices since the completion of the spin-off has significantly and adversely affected SSE's business, and in June 2016, SSE and its subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. In August 2016, SSE emerged from bankruptcy. In connection with SSE's recently completed bankruptcy, certain aspects of the spin-off could be challenged under fraudulent conveyance and transfer laws, in addition to other potential claims. Such a claim could seek to avoid transfers of assets to us or obligations incurred by SSE in connection with the spin-off and to impose other remedies, such as a judgment for the value of assets so transferred. Defending against such claims could be costly and could distract our management from other priorities. Although no assurance can be given as to the outcome of any claim, we believe we have a number of defenses to any such claim and any such claim would be without merit.

An interruption in operations at our headquarters could adversely affect our business.

Our headquarters are located in Oklahoma City, Oklahoma, an area that experiences severe weather events, including tornadoes and earthquakes. Our information systems and administrative and management processes are primarily provided to our various drilling projects and producing wells throughout the United States from this location, which could be disrupted if a catastrophic event, such as a tornado, power outage or act of terror, destroyed or severely damaged our headquarters. Any such catastrophic event could harm our ability to conduct normal operations and could adversely affect our business.

We have identified a material weakness in our internal controls. If we fail to remediate this material weakness or otherwise fail to develop, implement and maintain appropriate internal controls in future periods, our ability to report our financial condition and results of operations accurately and on a timely basis could be adversely affected.

We have identified a material weakness in our internal controls over the review of the valuation of proved oil and natural gas properties and the accuracy of impairment of oil and natural gas properties. Accordingly, based on our management's assessment, we believe that, as of December 31, 2016, our disclosure controls and procedures were not effective. We also determined that this material weakness existed as of March 31, 2016, June 30, 2016 and September 30, 2016. The specific material weakness and our remediation efforts are described in Item 9A, *Controls and Procedures*. A "material weakness" is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis. We cannot assure you that we will adequately remediate the material weakness or that additional material weaknesses in our internal controls will not be identified in the future. Any failure to maintain or implement required new or improved controls, or any difficulties we encounter in their implementation, could result in additional material weaknesses, or could result in material misstatements in our financial statements. These misstatements could result in restatements of our financial statements, cause us to fail to meet our reporting obligations or cause investors to lose confidence in our reported financial information.

We are in the process of remediating the identified material weakness in our internal controls, but we are unable at this time to estimate when the remediation effort will be completed. If we fail to remediate this material weakness, there will continue to be an increased risk that our future financial statements could contain errors that will be undetected. Further and continued determinations that there are material weaknesses in the effectiveness of our internal controls could reduce our ability to obtain financing or could increase the cost of any financing we obtain and require additional expenditures of resources to comply with applicable requirements. For more information relating to our internal controls and disclosure controls and procedures, and the remediation plan undertaken by us, see Item 9A, *Controls and Procedures*.

We do not anticipate paying dividends on our common stock in the near future.

In July 2015, our Board of Directors determined to eliminate quarterly cash dividends on our common stock. Accordingly, we do not intend to pay cash dividends on our common stock in the foreseeable future. We currently intend to retain any earnings for the future operation and development of our business, including exploration, development and acquisition activities. Any future dividend payments will require approval by the Board of Directors. In addition, dividends may be restricted by the terms of our debt agreements. Additionally, our Board of Directors may determine to suspend dividend payments on our preferred stock in the future. If we fail to pay dividends on our preferred stock with respect to six or more quarterly periods (whether or not consecutive), the holders of our preferred stock, voting as a single class, will be entitled at the next regular or special meeting of shareholders to elect two additional directors of the Company. As of December 31, 2016, we had previously failed to pay dividends on our outstanding preferred stock with respect to four quarterly periods.

Certain anti-takeover provisions may affect your rights as a shareholder.

Our certificate of incorporation authorizes our Board of Directors to set the terms of and issue preferred stock without shareholder approval. Our Board of Directors could use the preferred stock as a means to delay, defer or prevent a takeover attempt that a shareholder might consider to be in our best interest. In addition, our revolving credit facility and term loan facility contain terms that may restrict our ability to enter into change of control transactions, including requirements to repay borrowings under our revolving credit facility and to offer to purchase our term loan on a change in control. These provisions, along with specified provisions of the Oklahoma General Corporation Act and our certificate of incorporation and bylaws, may discourage or impede transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock.

ITEM 1B. *Unresolved Staff Comments*

Not applicable.

ITEM 2. *Properties*

Information regarding our properties is included in Item 1 and in the Supplementary Information included in Item 8 of Part II of this report.

ITEM 3. *Legal Proceedings*

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is currently indeterminate. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

2016 Shareholder Litigation. On April 19, 2016, a shareholder lawsuit was filed in the U.S. District Court for the Western District of Oklahoma against the Company and current and former directors and officers of the Company alleging, among other things, violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act, breach of fiduciary duties, waste of corporate assets, gross mismanagement and violations of Sections 10(b) and Rule 10b-5 of the Exchange Act related to actions allegedly taken by such persons since 2008. The lawsuit sought to assert derivative and direct claims, certification as a class action, damages, attorneys' fees and other costs. The District Court dismissed the plaintiffs' claims on August 30, 2016.

Regulatory and Related Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.

In addition, the Company received a DOJ subpoena and a voluntary document request from the SEC seeking information on our accounting methodology for the acquisition and classification of oil and natural gas properties and related matters. Chesapeake has engaged in discussions with the DOJ and SEC about these matters. On October 4, 2016, a securities class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and certain current directors and officers of the Company alleging, among other things, violations of federal securities laws for purported misstatements in the Company's SEC filings and other public disclosures regarding the Company's accounting for the acquisition and classification of oil and natural gas properties. The lawsuit seeks certification as a class action, damages, attorneys' fees and other costs.

Redemption of 2019 Notes. See Note 4 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a description of pending litigation regarding our redemption in May 2013 of our 6.775% Senior Notes due 2019 (the 2019 Notes).

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts and has settled and resolved other such cases and disputes.

Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. Plaintiffs have varying royalty provisions in their respective leases. Oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. The Company has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages with respect to royalty underpayment in various states, including, but not limited to, Texas, Pennsylvania, Ohio, Oklahoma, Kentucky, Louisiana and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ, U.S. Postal Service and state subpoenas or information requests seeking information on the Company's royalty payment practices.

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

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

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company's divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources.

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

Other Matters

In April 2016, a class action lawsuit on behalf of holders of the Company's 6.875% Senior Notes due 2020 (the 2020 Notes) and 6.125% Senior Notes due 2021 (2021 Notes) was filed in the U.S. District Court for the Southern District of New York relating to the Company's December 2015 debt exchange, whereby the Company privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible notes. The lawsuit alleges that the Company violated the Trust Indenture Act of 1939 and the implied covenant of good faith and fair dealing by benefiting themselves and a minority of noteholders who are qualified institutional buyers (QIBs). According to the lawsuit, as a result of the Company's private debt exchange in which only QIBs (and non-U.S. persons under Regulation S) were eligible to participate, the Company unjustly enriched itself at the expense of class members by reducing indebtedness and reducing the value of the 2020 Notes and the 2022 Notes. The lawsuit seeks damages and attorney's fees, in addition to declaratory relief that the debt exchange and the liens created for the benefit of the Second Lien Notes are null and void and that the debt exchange effectively resulted in a default under the indentures for the 2020 Notes and the 2021 Notes. In June 2016, the lawsuit was transferred to the United States District Court for the Western District of Oklahoma, and in October 2016, the Company filed a motion to dismiss for failure to state a claim. The District Court dismissed the plaintiffs' claims on February 8, 2017.

Environmental Proceedings

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

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

On December 12, 2016, CALLC and the PADEP entered into a Consent Order and Agreement with respect to alleged violations of the Pennsylvania Oil and Gas Act and the Pennsylvania Clean Streams Law in connection with contamination in the vicinity of one of CALLC's well pads in Sullivan County, Pennsylvania. Under the agreement CALLC committed to certain ongoing monitoring and operational obligations and agreed to pay a civil penalty of $280,695.

On October 14, 2016, we were named as a defendant in a putative class action in the U.S. District Court for the Western District of Oklahoma, alleging that we and the other defendants have operated produced water disposal wells in a manner that has caused earthquakes. The proposed class would consist of property owners in a twenty-six county area of Oklahoma. The petition seeks, among other relief, reimbursement of insurance premiums and an award of damages for injury to real property.

On February 16, 2016, we were named as a defendant in a lawsuit brought in the U.S. District Court for the Western District of Oklahoma by the Sierra Club. The complaint alleges that we and the other defendants, all exploration and production companies, have violated the federal Resource Conservation and Recovery Act by operating produced water disposal wells in a manner that has caused earthquakes. It requests a court order requiring substantial reduction of the amounts of produced water disposed of in such manner, the creation of an earthquake prediction center, and the reinforcement of purportedly vulnerable structures that could be impacted by earthquakes.

ITEM 4. *Mine Safety Disclosures*

Not applicable.

PART II

ITEM 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Price Range of Common Stock and Dividends

Our common stock trades on the New York Stock Exchange under the symbol "CHK". The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange and the amount of cash dividends declared per share:

	Common Stock		Dividend
	High	Low	Declared
Year Ended December 31, 2016:			
Fourth Quarter	$ 8.20	$ 5.14	$ —
Third Quarter	$ 8.15	$ 4.13	$ —
Second Quarter	$ 7.59	$ 3.53	$ —
First Quarter	$ 5.76	$ 1.50	$ —
Year Ended December 31, 2015:			
Fourth Quarter	$ 9.55	$ 3.56	$ —
Third Quarter	$ 11.90	$ 6.01	$ —
Second Quarter	$ 16.98	$ 10.94	$ —
First Quarter	$ 21.49	$ 13.38	$ 0.0875

As of February 6, 2017, there were approximately 2,000 holders of record of our common stock and approximately 347,000 beneficial owners.

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

In January 2016, we announced that we were suspending payment of dividends on each series of our outstanding convertible preferred stock. Suspension of the dividends did not constitute an event of default under our revolving credit facility or outstanding bond indentures. On February 15, 2017, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock and paid our dividends in arrears.

Our revolving credit facility and our term loan facility contain restrictions on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred. The certificates of designation for our preferred stock prohibit payment of cash dividends on our common stock unless we have declared and paid (or set apart for payment) full accumulated dividends on the preferred stock.

Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents information about repurchases of our common stock during the quarter ended December 31, 2016:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share[(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
				($ in millions)
October 1, 2016 through October 31, 2016	5,693	$ 6.12	—	$ 1,000
November 1, 2016 through November 30, 2016	2,026	$ 6.80	—	$ 1,000
December 1, 2016 through December 31, 2016	837	$ 7.06	—	$ 1,000
Total	8,556	$ 6.37	—	

(a) Reflects the surrender to the Company of shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock. Also includes shares of common stock purchased on behalf of Chesapeake's deferred compensation plan related to participant deferrals and Company matching contributions.

(b) In December 2014, the Company's Board of Directors authorized the repurchase of up to $1 billion in value of its common stock from time to time. The repurchase program does not have an expiration date. As of December 31, 2016, no repurchases had been made under the program.

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, 2016, 2015, 2014, 2013 and 2012. The data are derived from our audited consolidated financial statements, revised to reflect the reclassification discussed below. Beginning in the 2016 first quarter, we have reclassified our presentation of debt issuance costs related to term debt to be presented in the balance sheet as a direct reduction from the associated debt liability. 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.

	Years Ended December 31,				
	2016	2015	2014	2013	2012
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA:					
Total revenues	$ 7,872	$ 12,764	$ 23,125	$ 19,080	$ 13,422
Net income (loss) available to common stockholders[a]	$ (4,926)	$ (14,856)	$ 1,273	$ 474	$ (940)
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ (6.45)	$ (22.43)	$ 1.93	$ 0.73	$ (1.46)
Diluted	$ (6.45)	$ (22.43)	$ 1.87	$ 0.73	$ (1.46)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ —	$ 0.0875	$ 0.35	$ 0.35	$ 0.35
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 13,028	$ 17,314	$ 40,655	$ 41,663	$ 41,469
Long-term debt, net of current maturities	$ 9,938	$ 10,311	$ 11,058	$ 12,767	$ 12,015
Total equity (deficit)	$ (1,203)	$ 2,397	$ 18,205	$ 18,140	$ 17,896

(a) Includes $2.564 billion, $18.238 billion and $3.315 billion of full cost ceiling test write-downs on our oil and natural gas properties for the years ended December 31, 2016, 2015 and December 2012, respectively. In 2014 and 2013, we did not have any ceiling test impairments for our oil and natural gas properties.

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

Financial Data

The following table sets forth certain information regarding our production volumes, oil, natural gas and NGL sales, average sales prices received, and other operating income and expenses for the periods indicated:

	Years Ended December 31,		
	2016	2015	2014
Net Production:			
Oil (mmbbl)	33	42	42
Natural gas (bcf)	1,049	1,070	1,095
NGL (mmbbl)	24	28	33
Oil equivalent (mmboe)[(a)]	233	248	258
Oil, Natural Gas and NGL Sales ($ in millions):			
Oil sales	$ 1,351	$ 1,904	$ 3,778
Oil derivatives – realized gains (losses)[(b)]	97	880	(185)
Oil derivatives – unrealized gains (losses)[(b)]	(318)	(536)	859
Total oil sales	1,130	2,248	4,452
Natural gas sales	2,155	2,470	4,535
Natural gas derivatives – realized gains (losses)[(b)]	151	437	(191)
Natural gas derivatives – unrealized gains (losses)[(b)]	(500)	(157)	535
Total natural gas sales	1,806	2,750	4,879
NGL sales	360	393	1,023
NGL derivatives – realized gains (losses)[(b)]	(8)	—	—
NGL derivatives – unrealized gains (losses)[(b)]	—	—	—
Total NGL sales	352	393	1,023
Total oil, natural gas and NGL sales	$ 3,288	$ 5,391	$ 10,354
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 40.65	$ 45.77	$ 89.41
Natural gas ($ per mcf)	$ 2.05	$ 2.31	$ 4.14
NGL ($ per bbl)	$ 14.76	$ 14.06	$ 30.95
Oil equivalent ($ per boe)	$ 16.63	$ 19.23	$ 36.21
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 43.58	$ 66.91	$ 85.04
Natural gas ($ per mcf)	$ 2.20	$ 2.72	$ 3.97
NGL ($ per bbl)	$ 14.43	$ 14.06	$ 30.95
Oil equivalent ($ per boe)	$ 17.66	$ 24.54	$ 34.74
Other Operating Income ($ in millions):			
Marketing, gathering and compression net margin[(c)(d)]	$ (194)	$ 243	$ (11)
Oilfield services net margin	$ —	$ —	$ 115

	Years Ended December 31,		
	2016	2015	2014
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 3.05	$ 4.22	$ 4.69
Oil, natural gas and NGL gathering, processing and transportation	$ 7.98	$ 8.55	$ 8.43
Production taxes	$ 0.32	$ 0.40	$ 0.90
General and administrative[(e)]	$ 1.03	$ 0.95	$ 1.25
Oil, natural gas and NGL depreciation, depletion and amortization	$ 4.31	$ 8.47	$ 10.41
Depreciation and amortization of other assets	$ 0.45	$ 0.53	$ 0.90
Interest expense[(f)]	$ 1.18	$ 1.30	$ 0.63
Interest Expense ($ in millions):			
Interest expense	$ 286	$ 329	$ 173
Interest rate derivatives – realized (gains) losses[(g)]	(11)	(6)	(12)
Interest rate derivatives – unrealized (gains) losses[(g)]	21	(6)	(72)
Total interest expense	$ 296	$ 317	$ 89

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

(b) Realized gains (losses) include the following items: (i) settlements and accruals for settlements of undesignated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period production revenues, and (iii) gains (losses) related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains (losses) include the change in fair value of open derivatives scheduled to settle against future period production revenues (including current period settlements for option premiums and early terminated derivatives) offset by amounts reclassified as realized gains (losses) during the period.

(c) Includes revenue and operating costs. See *Depreciation and Amortization of Other Assets* under *Results of Operations* for details of the depreciation and amortization associated with our marketing, gathering and compression segment.

(d) For the years ended December 31, 2016 and 2015, we recorded unrealized losses of $297 million and unrealized gains of $296 million, respectively, on the fair value of our supply contract derivative. Additionally, in 2016, we sold the long-term natural gas supply contract to a third party for cash proceeds of $146 million. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for discussion related to this instrument.

(e) Excludes restructuring and other termination costs.

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

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

Overview

For an overview of our business and strategy, please see *Our Business and Business Strategy* in Item 1 of this report.

Operating Results

Our 2016 production of 233 mmboe consisted of 33 mmbbls of oil (14% on an oil equivalent basis), 1.0 tcf of natural gas (75% on an oil equivalent basis), and 24 mmbbls of NGL (11% on an oil equivalent basis). Our daily production for 2016 averaged approximately 635 mboe, a decrease of 6% from 2015. Compared to 2015, average daily oil production decreased by 20% or approximately 23 mbbls per day; average daily natural gas production decreased by 2%, or approximately 64 mmcf per day; and average daily NGL production decreased by 13%, or approximately 10 mbbls per day. Our oil and NGL production decreased primarily as a result of the sale of certain of our Mid-Continent assets in 2016 and 2015 as well as a significant reduction in drilling activity. Adjusted for asset sales, our total daily production was comparable between 2016 and 2015. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $901 million to $3.866 billion in 2016 compared to $4.767 billion in 2015, primarily due to significant decreases in the prices received for oil and natural gas sold in addition to lower oil, natural gas and NGL volumes sold. See *Results of Operations* below for additional details.

Capital Expenditures

Our drilling and completion capital expenditures during 2016 were approximately $1.316 billion and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $130 million, for a total of approximately $1.446 billion. In 2016, we operated an average of 10 rigs, a decrease of 18 rigs, or 64%, compared to 2015. As a result of lower drilling and completion activity, drilling and completion expenditures decreased approximately $1.7 billion in 2016 compared to 2015. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $101 million compared to 2015.

Our capitalized interest was approximately $251 million and $424 million in 2016 and 2015, respectively. The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. Including capitalized interest, total capital investments were approximately $1.7 billion in 2016 compared to $3.6 billion for 2015, a decrease of 53%.

Based on planned activity levels for 2017, we project that 2017 capital expenditures for drilling and completions, leasehold, geological and geophysical and other property and equipment will be $1.9 - $2.5 billion, inclusive of capitalized interest, as compared to $1.7 billion of capital expenditures in 2016. See *Liquidity and Capital Resources* for additional information on how we plan to fund our capital budget.

Strategic Developments

Debt Issuances

In December 2016, we issued in a private placement $1.0 billion principal amount of unsecured 8.00% Senior Notes due 2025. In October 2016, we issued in a private placement $1.25 billion principal amount of unsecured 5.5% Convertible Senior Notes due 2026, which are convertible, under certain specified circumstances, into cash, common stock or a combination of cash and common stock, at our election. In August 2016, we entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion. We used the net proceeds from these issuances primarily to purchase and retire senior notes and contingent convertible senior notes as described below, with a focus on retiring debt scheduled to mature or that could be put to us in 2017 and 2018.

Debt Retirements

In January 2017, we repurchased in the open market approximately $221 million principal amount of our outstanding debt scheduled to mature or that could be put to us in 2018 and 2020 for $224 million. On January 20, 2017, we redeemed our $133 million principal amount of outstanding 6.5% Senior Notes due 2017. On January 6, 2017, we purchased and retired approximately $287 million principal amount of our outstanding contingent convertible senior notes and $2 million principal amount of our outstanding senior notes for an aggregate of $286 million pursuant to tender offers.

In 2016, we used the proceeds from our senior notes, convertible notes and term loan issuances to purchase and retire $2.035 billion aggregate principal amount of our outstanding senior notes and $849 million aggregate principal amount of our outstanding contingent convertible senior notes for an aggregate purchase price of $2.734 billion pursuant to tender offers, open market repurchases and repayment upon maturity. Additionally, we privately negotiated exchanges of (i) approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of our common stock, and (ii) approximately $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of our common stock.

Credit Facility Amendment

In April 2016, we further amended our senior secured revolving credit facility agreement. Pursuant to the amendment, our borrowing base was reaffirmed in the amount of $4.0 billion (as a result of subsequent asset sales, our borrowing base was reduced to $3.8 billion) and our next scheduled borrowing base redetermination date was postponed until June 15, 2017, with the consenting lenders agreeing not to exercise their interim redetermination right prior to that date. The amendment also modified the credit agreement to provide for, among other things, (i) the suspension or modification of certain financial covenants, and (ii) the granting of liens and security interests on substantially all of our assets, including mortgages encumbering 90% of our proved oil and gas properties that constitute borrowing base properties, all derivative contracts and personal property, subject to certain agreed-upon carve outs. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the terms of our revolving credit facility.

Preferred Stock Exchanges and Conversions

In January 2017, we completed private exchanges of an aggregate of approximately 10.0 million shares of our common stock for (i) 150,948 shares of 5.00% Cumulative Convertible Preferred Stock (Series 2005B), (ii) 72,600 shares of 5.75% Cumulative Convertible Preferred Stock and (iii) 12,500 shares of 5.75% Cumulative Convertible Preferred Stock (Series A). The preferred stock exchanged represents approximately $100 million of liquidation value.

In October and November 2016, we completed private exchanges of an aggregate of approximately 119.2 million shares of our common stock for (i) 134,000 shares of 5.00% Cumulative Convertible Preferred Stock (Series 2005B), (ii) 629,271 shares of 5.75% Cumulative Convertible Preferred Stock and (iii) 622,936 shares of 5.75% Cumulative Convertible Preferred Stock (Series A). The preferred stock exchanged represents approximately $1.3 billion of liquidation value.

In February and March 2016, certain preferred shareholders converted (i) 24,601 shares of 5.75% Cumulative Convertible Preferred Stock and (ii) 1,201 shares of 5.75% Cumulative Convertible Preferred Stock (Series A) into an aggregate of approximately 1 million shares of our common stock. The preferred stock converted represents approximately $26 million of liquidation value.

In January 2016, we suspended dividend payments on our convertible preferred stock to provide additional liquidity in the depressed commodity environment that existed throughout 2016. On February 15, 2017, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock and paid our dividends in arrears. The preferred stock exchanges and conversions completed in 2016 and 2017 eliminated approximately $80 million of annual dividend obligations.

Divestitures

During 2016 and into 2017, we sold oil and natural gas properties and related assets for net proceeds of approximately $2.3 billion, providing additional liquidity for debt reduction and operations. In addition, we purchased five of our VPP transactions for approximately $386 million, removing all future obligations we have with those VPPs.

In February 2017, we sold a portion of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $465 million, subject to certain customary post-closing adjustments. Included in the sale were approximately 41,500 net acres. The sale also included 326 operated and non-operated wells currently producing approximately 50 mmcf of gas per day.

In January 2017, we sold a portion of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $450 million, subject to certain customary post-closing adjustments. Included in the sale were approximately 78,000 net acres. The sale also included 250 wells currently producing approximately 30 mmcf of gas per day.

In October 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. We sold approximately 212,000 net developed and undeveloped acres, approximately 2,900 operated wells which produced an average of approximately 59 mboe per day in the 2016 third quarter, along with other property and equipment. We simultaneously terminated most of our future natural gas gathering and transportation 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 may be required to pay additional amounts in respect of certain title and environmental contingencies. Additionally, we recognized a charge of $284 million related to the impairment of other fixed assets sold in the divestiture. By exiting the Barnett Shale, we eliminated approximately $1.9 billion of total future midstream and downstream commitments, leading to an expected increase in our operating income for 2017 through 2019 of $200 to $300 million annually.

In December 2016, 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 related to other fixed assets sold in the divestiture. In connection with this divestiture, we purchased 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.

In 2016, we sold certain of our other noncore assets for net proceeds of approximately $1.048 billion after post-closing adjustments. In conjunction with certain of these sales, we purchased four of our VPP transactions for approximately $259 million. A majority of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas. We continue to pursue the sale of assets that do not fit in our strategic priorities.

Gathering, Processing and Transportation Agreements

In February 2017, we paid approximately $290 million to assign an oil transportation agreement. This assignment is expected to reduce our future oil transportation commitments by approximately $450 million. The assignment is effective April 1, 2017. In addition, we terminated future natural gas transportation commitments related to divested assets of approximately $110 million for a cash payment of approximately $100 million. This termination was effective March 1, 2017.

In December 2016, we restructured our natural gas gathering and service agreement in our Powder River Basin operating area with Williams Partners L.P. and Crestwood Equity Partners L.P. The restructured services will replace the current cost-of-service arrangement and improve economics which support increased development across an expanded area of dedication in the region. The restructured services were effective January 1, 2017, for a 20-year term.

In 2016, we renegotiated our natural gas gathering agreement with Williams in our Mid-Continent operating area in exchange for a net $57 million payment. We estimate a 36% reduction in Mid-Continent gathering costs over the life of the contract. This amount will be amortized to oil, natural gas and NGL gathering, processing and transportation expense over the life of the agreement.

In 2016, we amended certain of our firm transportation agreements in the Haynesville, Barnett and Eagle Ford operating areas, which will reduce our firm transportation volume commitments and fees. We estimate a benefit of approximately $650 million gross ($415 million net) over the term of the contracts, including $80 million gross ($50 million net) in lower unused demand charges for the underutilized capacity and lower transportation fees in 2016.

Other

In 2016, we sold a long-term natural gas supply contract for $146 million in cash proceeds.

Liquidity and Capital Resources

Liquidity Overview

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

As of December 31, 2016, we had a cash balance of $882 million compared to $825 million as of December 31, 2015, and we had a net working capital deficit of $1.506 billion, compared to a net working capital deficit of $1.205 billion as of December 31, 2015. We made significant progress in 2016 and into 2017 to reduce near-term debt maturities, including reducing our 2017 debt maturities by $1.878 billion, or 99%, and our 2018 debt maturities by $815 million, or 93%. As of February 24, 2017, we had $77 million of debt maturing or that could be put to us in 2017 and 2018. As of December 31, 2016, we had $2.749 billion of borrowing capacity available under our revolving credit facility, with no outstanding borrowings and $1.036 billion utilized for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation). See Note 3 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. Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures, meet our debt service requirements and fund our other commitments and obligations for the next 12 months.

In 2016, we took the following measures to improve our liquidity:

- entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion;
- issued $1.25 billion principal amount of unsecured 5.5% Convertible Senior Notes due 2026;
- issued $1.0 billion principal amount of unsecured 8.00% Senior Notes due 2025;
- exchanged 109 million shares of common stock for $577 million principal amount of our outstanding senior notes and contingent convertible senior notes, including $373 million principal amount that was scheduled to mature or could be put to us in 2017 or 2018;
- retired $2.884 billion principal amount of our outstanding senior notes and contingent convertible notes through purchases in the open market, tender offers or repayment upon maturity for $2.734 billion, including $1.621 billion principal amount that was scheduled to mature or could be put to us in 2017 and 2018;
- exchanged 120.2 million shares of common stock for $1.3 billion liquidation value of our preferred stock, eliminating $74 million of annual dividend obligations;
- further amended our revolving credit agreement to reaffirm our borrowing base, postpone our next scheduled borrowing base redetermination date and modify or suspend certain credit agreement financial covenants; and
- mitigated a portion of our downside exposure to commodity prices through derivative contracts, suspended dividend payments on our convertible preferred stock and divested assets to increase our liquidity.

Additionally in 2017, we retired $643 million aggregate principal amount of our outstanding senior notes and contingent convertible senior notes pursuant to tender offers, open market repurchases and redemptions. We also repaid our 6.25% Euro-denominated Senior Notes due 2017 upon maturity. We completed private exchanges of an aggregate of approximately 10.0 million shares of our common stock for approximately $100 million liquidation value of our preferred stock.

We may continue to access the capital markets or otherwise incur debt to refinance a portion of our outstanding indebtedness and improve our liquidity.

As operator of a substantial portion of our oil and natural gas properties under development, we have significant control and flexibility over the timing and execution of our development plan, enabling us to reduce our capital spending as needed. Our forecasted 2017 capital expenditures, inclusive of capitalized interest, are $1.9 - $2.5 billion, compared to our 2016 capital spending level of $1.7 billion. We currently plan to use cash flow from operations, cash on hand and availability under our revolving bank credit facility to fund our capital expenditures during 2017. We had liquidity (calculated as cash on hand and availability under our revolving credit facility) of approximately $3.4 billion as of February 24, 2017. We expect to generate additional liquidity with proceeds from future sales of assets that we determine do not fit our strategic priorities. Management continues to review operational plans for 2017 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL. We closely monitor the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our revolving credit facility.

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 24, 2017, we have received requests and posted approximately $275 million in collateral under such arrangements (excluding the supersedeas bond with respect to the 2019 Notes litigation). We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $451 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business relationships with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business arrangements and by offsetting amounts that the counterparty owes us. Any posting of collateral consisting of cash or letters of credit reduces availability under our revolving credit facility and negatively impacts our liquidity.

In addition, during the next 12 months, we may be required to pay up to $440 million in connection with the judgment against us related to the redemption at par value of our 6.775% Senior Notes due 2019. In connection with our appeal of the decision by the U.S. District Court for the Southern District of New York regarding the redemption, we posted a supersedeas bond in the amount of $461 million in July 2015, which is reflected as an outstanding letter of credit under our revolving credit facility. This contingent payment is fully accrued on our consolidated balance sheet. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the recent developments in this litigation.

To add more certainty to our future estimated cash flows by mitigating our downside exposure to lower commodity prices, as of February 24, 2017, we have downside price protection, through open swaps, on approximately 68% of our projected 2017 oil production at an average price of $50.19 per bbl. We also have downside price protection, through open swaps and collars, on approximately 71% of our projected 2017 natural gas production at an average price of $3.07 per mcf, of which 3% is hedged under two-way collar arrangements based on an average bought put NYMEX price of $3.00 per mcf. We also have downside price protection, through open swaps, on approximately 7% of our projected 2017 NGL production at an average price of $0.28 per gallon of ethane.

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

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the years ended December 31, 2016, 2015 and 2014. See Notes 12, 14 and 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, investments and other assets, respectively.

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Cash provided by (used in) operating activities	$ (204)	$ 1,234	$ 4,634
Proceeds from issuance of term loan	1,476	—	—
Proceeds from long-term debt, net	2,210	—	2,966
Proceeds from oilfield services long-term debt, net	—	—	888
Divestitures of proved and unproved properties	1,406	189	5,813
Sales of other property and equipment	131	89	1,003
Proceeds from sales of investments	—	—	239
Other	—	52	37
Total sources of cash and cash equivalents	$ 5,019	$ 1,564	$ 15,580

Cash used in operating activities was $204 million in 2016 compared to cash provided by operating activities of $1.234 billion in 2015 and $4.634 billion in 2014. The decrease is primarily the result of lower realized prices for the oil and natural gas we sold in addition to lower volumes of oil, natural gas and NGL sold, partially offset by decreases in certain of our operating expenses. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, impairments, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See further discussion below under *Results of Operations*.

The following table reflects the proceeds received from issuances of debt in 2016, 2015 and 2014. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

	Years Ended December 31,					
	2016		2015		2014	
	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds
	($ in millions)					
Convertible senior notes	$ 1,250	$ 1,235	$ —	$ —	$ —	$ —
Senior notes[(a)]	1,000	975	—	—	3,500	3,460
Term loans[(a)]	1,500	1,476	—	—	400	394
Total	$ 3,750	$ 3,686	$ —	$ —	$ 3,900	$ 3,854

(a) Our 2015 debt exchange of certain outstanding unsecured senior notes and contingent notes for Second Lien Notes did not result in any additional debt issued or proceeds received. The 2014 amounts include debt issued in connection with the spin-off of our oilfield services business. All deferred charges and debt balances related to the spin-off were removed from our consolidated balance sheet as of June 30, 2014. See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the spin-off.

We currently plan to use cash flow from operations, cash on hand and our revolving credit facility to fund our capital expenditures during 2017. We expect to generate additional liquidity with proceeds from future sales of assets that we determine do not fit our strategic priorities. Prior to June 2014, we also utilized a $500 million oilfield services credit facility. This facility was terminated in June 2014 in connection with the spin-off of our oilfield services business. See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the spin-off. Under our revolving credit facilities, we borrowed and repaid $5.146 billion in 2016, we had no borrowings or repayments in 2015 and we borrowed $7.406 billion and repaid $7.788 billion in 2014.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for 2016, 2015 and 2014:

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Oil and Natural Gas Expenditures:			
Drilling and completion costs[(a)]	$ 1,276	$ 3,083	$ 4,495
Acquisitions of proved and unproved properties	571	135	793
Interest capitalized on unproved leasehold	236	410	604
Total oil and natural gas expenditures	2,083	3,628	5,892
Other Uses of Cash and Cash Equivalents:			
Cash paid to repurchase debt	2,734	508	3,362
Cash paid for title defects	69	—	—
Cash paid to repurchase noncontrolling interest of CHK C-T[(b)]	—	143	—
Cash paid to purchase leased rigs and compressors	—	—	499
Cash paid to repurchase CHK Utica preferred shares[(b)]	—	—	1,254
Cash paid on financing derivatives[(c)]	—	—	53
Payments on credit facility borrowings, net	—	—	382
Additions to other property and equipment	37	143	227
Dividends paid	—	289	405
Distributions to noncontrolling interest owners	10	85	173
Additions to investments	—	1	—
Other	29	50	62
Total other uses of cash and cash equivalents	2,879	1,219	6,417
Total uses of cash and cash equivalents	$ 4,962	$ 4,847	$ 12,309

(a) Net of $51 million and $679 million in drilling and completion carries received from our joint venture partners during 2015 and 2014, respectively.

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

(c) Reflects derivatives deemed to contain, for accounting purposes, a significant financing element at contract inception.

Our primary use of funds is for drilling and completion costs on our oil and natural gas properties. Our drilling and completion costs decreased in 2016 compared to 2015 and 2014, primarily as a result of significantly decreased activity. During 2016, our average operated rig count was 10 rigs compared to an average operated rig count of 28 rigs in 2015 and 64 rigs in 2014. Our acquisitions of proved and unproved properties increased in 2016 compared to 2015, primarily resulting from purchases of oil and natural gas interests previously sold to third parties in connection with five of our VPP transactions for approximately $387 million.

Capital expenditures related to our midstream assets, oilfield services business, and other fixed assets were $37 million in 2016 compared to $143 million in 2015 and $227 million in 2014. The reduction of these expenditures in 2016 and 2015 as compared to 2014 is primarily the result of the spin-off of our oilfield services business in June 2014 and reductions in construction expenditures on our corporate headquarters and field offices.

In 2014, we purchased rigs and compressors previously sold under long-term lease arrangements for approximately $499 million as part of a strategic initiative to reduce complexity and future commitments as well as to facilitate asset sales and the spin-off of our oilfield services business in June 2014.

In 2016, we used $2.734 billion of cash to repurchase $2.884 billion principal amount of debt. In addition to the repayment at maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $141 million principal amount of our contingent convertible senior notes and $325 million principal amount of our outstanding senior notes for $386 million in aggregate. Additionally in 2016, we used the proceeds from our term loan facility, convertible note issuance, senior note issuance and cash on hand to purchase and retire $1.451 billion principal amount of our senior notes and $708 million principal amount of our contingent convertible senior notes for an aggregate $2.089 billion pursuant to tender offers.

In 2015, we used $508 million of cash to reduce debt. As required by the terms of the indenture for our 2.75% Contingent Convertible Senior Notes due 2035 (the 2035 Notes), the holders were provided the option to require us to purchase on November 15, 2015, all or a portion of the holders' 2035 Notes at par plus accrued and unpaid interest up to, but excluding, November 15, 2015. On November 16, 2015, we paid an aggregate of approximately $394 million to purchase all of the 2035 Notes that were tendered and not withdrawn. An aggregate of $2 million principal amount of the 2035 Notes remains outstanding. In addition, during November and December 2015, we repurchased through privately negotiated transactions, approximately $119 million aggregate principal amount of our 3.25% Senior Notes due 2016 for approximately $114 million.

In 2014, we used $3.362 billion of cash to reduce debt. We issued $3.0 billion in aggregate principal amount of senior notes at par. The offering included two series of notes: $1.5 billion in aggregate principal amount of Floating Rate Senior Notes due 2019 and $1.5 billion in aggregate principal amount of 4.875% Senior Notes due 2022. We used a portion of the net proceeds of $2.966 billion to repay the borrowings under, and terminate, our $2.0 billion term loan credit facility. We used the remaining proceeds along with cash on hand to redeem the $97 million principal amount of 6.875% Senior Notes due 2018 and to purchase and redeem the $1.265 billion principal amount of the 9.5% Senior Notes due 2015 for $1.454 billion.

We paid dividends on our preferred stock of $171 million in each of 2015 and 2014. We paid dividends on our common stock of $118 million in 2015 and $234 million in 2014. We eliminated common stock dividends effective in the 2015 third quarter and suspended preferred stock dividends effective in the 2016 first quarter. On February 15, 2017, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock and paid our dividends in arrears.

Term Loan Facility

In 2016, we entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion for net proceeds of approximately $1.476 billion. Our obligations under the new facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility, second lien notes and senior notes and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 7.50% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 6.50% per annum, subject to a 2.00% ABR floor, at our option. The loan was made at par without original discount. We used the net proceeds to finance tender offers for our unsecured notes. The term loan matures in August 2021 and voluntary prepayments are subject to a make-whole premium prior to the second anniversary of the closing of the term loan, a premium to par of 4.25% from the second anniversary until but excluding the third anniversary, a premium to par of 2.125% from the third anniversary until but excluding the fourth anniversary and at par beginning on the fourth anniversary. The term loan may be subject to mandatory prepayments and offers to purchase with net cash proceeds of certain issuances of debt, certain asset sales and other dispositions of collateral and upon a change of control. See Note 3 of the notes to our consolidated financial statements included in Item 8 for further discussion of the term loan facility.

Revolving Credit Facility

We have a $4.0 billion senior secured revolving credit facility (currently subject to a $3.8 billion borrowing base) that matures in December 2019. As of December 31, 2016, we had no outstanding borrowings under the revolving credit facility and had used $1.036 billion of the revolving credit facility for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation). See *Liquidity Overview* above for additional information on our collateral postings. Borrowings under the facility bear interest at a variable rate. We are required to secure our obligations under the facility with liens on certain of our oil and natural gas properties, with the liens to be released upon the satisfaction of specific conditions. The applicable interest rates under the facility fluctuate based on the percentage of the borrowing base used. In 2016, we amended our revolving credit facility to provide covenant relief and affirm our $4.0 billion borrowing base. Our borrowing base may be reduced if we dispose of a certain percentage of the value of the collateral securing the facility. As a result of certain asset sales discussed in Note 12 of the notes to our consolidated financial statements included in Item 8 of this report and certain other sales of collateral since the date of the most recent amendment, our borrowing base was reduced to $3.8 billion in October 2016. See Note 3 of the notes to our consolidated financial statements included in Item 8 of Part II for further discussion of the terms of the revolving credit facility, as amended. As of December 31, 2016, our interest coverage ratio was approximately 2.04 to 1.0, and we were in compliance with all applicable financial covenants under the credit agreement.

Hedging Arrangements

In 2015, we began entering into bilateral hedging agreements. The counterparties' and our obligations under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. In 2016, certain of our counterparties that are also lenders (or affiliates of our lenders) under our revolving credit facility entered into derivative contracts to be secured by the same collateral that secures our revolving credit facility. This allows us to reduce any letters of credit posted as security with those counterparties.

Senior Note Obligations

Our senior note obligations consisted of the following as of December 31, 2016:

	December 31, 2016	
	Principal Amount	Carrying Amount
	($ in millions)	
6.25% euro-denominated senior notes due 2017[(a)]	$ 258	$ 258
6.5% senior notes due 2017	134	134
7.25% senior notes due 2018	64	64
Floating rate senior notes due 2019	380	380
6.625% senior notes due 2020	780	780
6.875% senior notes due 2020	279	279
6.125% senior notes due 2021	550	550
5.375% senior notes due 2021	270	270
4.875% senior notes due 2022	451	451
8.00% senior secured second lien notes due 2022[(b)]	2,419	3,409
5.75% senior notes due 2023	338	338
8.00% senior notes due 2025	1,000	1,000
5.5% convertible senior notes due 2026[(c)(d)]	1,250	811
2.75% contingent convertible senior notes due 2035[(e)]	2	2
2.5% contingent convertible senior notes due 2037[(d)(e)]	114	112
2.25% contingent convertible senior notes due 2038[(d)(e)]	200	180
Debt issuance costs	—	(41)
Discount on senior notes	—	(16)
Interest rate derivatives[(f)]	—	3
Total senior notes, net	8,489	8,964
Less current maturities of senior notes, net[(g)]	(506)	(503)
Total long-term senior notes, net	$ 7,983	$ 8,461

(a) The principal amount shown is based on the exchange rate of $1.0517 to €1.00 as of December 31, 2016. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for information on our related foreign currency derivatives.

(b) The carrying amount as of December 31, 2016, includes a premium of $990 million associated with a troubled debt restructuring. The premium is being amortized based on an effective yield method.

(c) The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash, common stock or a combination of cash and common stock, at our election.

(d) The carrying amount as of December 31, 2016, is reflected net of a discount associated with the equity component of our convertible and contingent convertible senior notes of $461 million.

(e) The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. We may redeem our 2.75% Contingent Convertible Senior Notes due 2035 at any time. The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date.

(f) See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for discussion related to these instruments.

(g) As of December 31, 2016, current maturities of long-term debt, net includes our 6.25% Euro-denominated Senior Notes due January 2017, 6.5% Senior Notes due 2017 and our 2037 Notes. As discussed in footnote (b) above and in Note 3 of the notes to our consolidated financial statements included in Item 8 of this report, the holders of our 2037 Notes could exercise their individual demand repurchase rights on May 15, 2017, which would require us to repurchase all or a portion of the principal amount of the notes. As of December 31, 2016, there was $2 million of discount associated with the equity component of the 2037 Notes.

For further discussion and details regarding our senior notes and convertible senior notes, see Note 3 of the notes to our consolidated financial statements included in Item 8 of this report.

Credit Risk

Derivative instruments that enable us to manage our exposure to oil, natural gas and NGL prices, as well as to foreign currency volatility, expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2016, our oil, natural gas, NGL and cross currency derivative instruments were spread among 12 counterparties. Additionally, the counterparties under our commodity hedging arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($840 million as of December 31, 2016) and exploration and production companies that own interests in properties we operate ($156 million as of December 31, 2016). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties that are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2016, 2015 and 2014, we recognized $10 million, $4 million and $2 million, respectively, of bad debt expense related to potentially uncollectible receivables. Additionally, during 2015, we recorded $22 million of impairment of a note receivable related to a previous asset sale as a result of the increased credit risk associated with declining commodity prices.

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to contractual obligations and off-balance sheet commitments. As of December 31, 2016, these arrangements and transactions included (i) operating lease agreements, (ii) volumetric production payments (VPPs) (to purchase production and pay related production expenses and taxes in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit, (vii) open gathering and transportation commitments, and (viii) various other commitments we enter into in the ordinary course of business which could result in a future cash obligation. See Notes 4 and 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of commitments and VPPs, respectively.

The table below summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2016.

	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			($ in millions)		
Long-term debt:					
Principal[(a)]	$ 9,989	$ 506	$ 644	$ 3,381	$ 5,458
Interest	3,969	664	1,300	1,101	904
Operating lease obligations[(b)]	9	4	5	—	—
Operating commitments[(c)]	11,269	1,578	2,421	2,045	5,225
Unrecognized tax benefits[(d)]	97	—	—	97	—
Standby letters of credit	1,036	1,036	—	—	—
Other	29	6	8	9	6
Total contractual cash obligations[(e)]	$ 26,398	$ 3,794	$ 4,378	$ 6,633	$ 11,593

(a) Total principal amount of debt maturities, using the earliest demand repurchase date for contingent convertible senior notes.

(b) See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our operating lease obligations.

(c) See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for a description of gathering, processing and transportation agreements, drilling contracts and pressure pumping contracts.

(d) See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a description of unrecognized tax benefits.

(e) 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 11 and 20, 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. This table also does not include our costs to produce reserves attributable to non-expense-bearing royalty and other interests in our properties, including VPPs, which are discussed below.

As the operator of the properties from which VPP volumes have been sold, we bear the cost of producing the reserves attributable to these interests, which we include as a component of production expenses and production taxes in our consolidated statements of operations in the periods these costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining our full cost ceiling test for impairment purposes and in determining our standardized measure. The amount of VPP-related production expenses and taxes, based on cost levels as of December 31, 2016, pursuant to SEC reporting requirements, was estimated to be approximately $19 million for the next twelve months and $76 million over the remaining life on an undiscounted basis, or approximately $18 million and $67 million, respectively, on a discounted basis using an annual discount rate of 10%. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all. We have committed to purchase natural gas and liquids produced that are associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

See Notes 4 and 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of commitments and VPPs, respectively.

Derivative Activities

Oil, Natural Gas and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the Company's derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading. As of December 31, 2016, our oil, natural gas and NGL derivative instruments consisted of swaps, options, collars and basis protection swaps. Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* contains a description of each of these instruments and gains and losses on oil, natural gas and NGL derivatives during 2016, 2015 and 2014. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our commodity derivative activities allow us to predict with greater certainty the effective prices we will receive for our hedged production. We closely monitor the fair value of our derivative contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or minimize a loss. Commodity markets are volatile and Chesapeake's derivative activities are dynamic.

Mark-to-market positions under commodity derivative contracts fluctuate with commodity prices. As described under *Hedging Arrangements* in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report, the counterparties' and our obligation under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. In 2016, certain of our counterparties that are also lenders under our revolving credit facility entered into derivative contracts to be secured by the same collateral that secures the revolving credit facility. This will allow us to reduce any letters of credit posted as security with those counterparties.

The estimated fair values of our oil, natural gas and NGL derivative contracts as of December 31, 2016 and 2015 are provided below. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information concerning the fair value of our oil and natural gas derivative instruments.

	December 31,	
	2016	2015
	($ in millions)	
Derivative assets (liabilities):		
Oil fixed-price swaps	$ (140)	$ 144
Oil call options	(1)	(7)
Natural gas fixed-price swaps	(349)	229
Natural gas collars	(9)	—
Natural gas call options	—	(99)
Natural gas basis protection swaps	(5)	—
NGL fixed-price swaps	—	—
Estimated fair value	$ (504)	$ 267

Changes in the fair value of oil and natural gas derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of settled designated derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. As of December 31, 2016, 2015 and 2014, accumulated other comprehensive income included unrealized losses, net of related tax effects, totaling $97 million, $113 million and $136 million, respectively, associated with commodity derivative contracts. Based upon the market prices at December 31, 2016, we expect to transfer approximately $22 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. A detailed explanation of accounting for oil, natural gas and NGL derivatives appears under *Application of Critical Accounting Policies – Derivatives* elsewhere in this Item 7.

Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and revolving credit facility, we enter into interest rate derivatives.

For interest rate derivative contracts designated as fair value hedges, changes in fair values of the derivatives are recorded on the consolidated balance sheets as assets or (liabilities), with corresponding offsetting adjustments to the debt's carrying value. Changes in the fair value of derivatives not designated as fair value hedges, which occur prior to their maturity (i.e., temporary fluctuations in mark-to-market values), are reported currently in the consolidated statements of operations as interest expense.

Gains or losses from interest rate derivative contracts are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2016, 2015 and 2014 are presented below in *Results of Operations – Interest Expense*, and a detailed explanation of accounting for interest rate derivatives appears under *Application of Critical Accounting Policies – Derivatives* elsewhere in this Item 7.

Foreign Currency Derivatives

On December 6, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. In December 2015, we exchanged and subsequently retired €42 million in aggregate principal amount of these senior notes in the private exchange described above, and we simultaneously unwound the cross currency swaps for the same principal amount. During 2016, in connection with our tender offers, we retired €56 million in aggregate principal amount of our 6.25% Euro-denominated Senior Notes due 2017, and we simultaneously unwound the cross currency swaps for the same principal amount at a cost of $13 million. A detailed explanation of accounting for foreign currency derivatives appears under *Application of Critical Accounting Policies – Derivatives* elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2016, Chesapeake had a net loss of $4.399 billion, or $6.45 per diluted common share, on total revenues of $7.872 billion. This compares to a net loss of $14.635 billion, or $22.43 per diluted common share, on total revenues of $12.764 billion for the year ended December 31, 2015 and net income of $2.056 billion, or $1.87 per diluted share, on total revenues of $23.125 billion for the year ended December 31, 2014. The net loss in 2016 was primarily driven by non-cash impairment of oil and natural gas properties and impairments of fixed assets and other while the net loss in 2015 was primarily driven by non-cash impairments of our oil and natural gas properties. See *Impairment of Oil and Natural Gas Properties* and *Impairments of Fixed Assets and Other* below. The decreases in total revenues in 2016 and 2015 were primarily driven by decreases in the average realized prices we received for oil and natural gas production, lower production volumes, increased unrealized hedging losses and a decrease in the volumes sold and the prices received by our marketing affiliate on behalf of third-party producers.

Oil, Natural Gas and NGL Sales. During 2016, oil, natural gas and NGL sales were $3.288 billion compared to $5.391 billion in 2015 and $10.354 billion in 2014. In 2016, Chesapeake sold 233 mmboe for $3.866 billion at a weighted average price of $16.63 per boe (excluding the effect of derivatives), compared to 248 mmboe sold in 2015 for $4.767 billion at a weighted average price of $19.23 per boe (excluding the effect of derivatives) and 258 mmboe sold in 2014 for $9.336 billion at a weighted average price of $36.21 per boe (excluding the effect of derivatives). The decrease in the price received per boe in 2016 compared to 2015 resulted in a $606 million decrease in revenues, and decreased sales volumes resulted in a $295 million decrease in revenues, for a total decrease in revenues of $901 million (excluding the effect of derivatives).

For 2016, our average price received per barrel of oil (excluding the effect of derivatives) was $40.65, compared to $45.77 in 2015 and $89.41 in 2014. Natural gas prices received per mcf (excluding the effect of derivatives) were $2.05, $2.31 and $4.14 in 2016, 2015 and 2014, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $14.76, $14.06 and $30.95 in 2016, 2015 and 2014, respectively.

Gains and losses from our oil and natural gas derivatives resulted in a net decrease in oil, natural gas and NGL revenues of $578 million in 2016 and net increases of $624 million and $1.018 billion in 2015 and 2014, respectively. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of this report for a complete listing of all of our derivative instruments as of December 31, 2016.

A change in oil, natural gas and NGL prices has a significant impact on our revenues and cash flows. Assuming our 2016 production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in 2016 revenues and cash flows of approximately $33 million and $32 million, respectively, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2016 revenues and cash flows of approximately $105 million and $104 million, respectively, and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease in 2016 revenues and cash flows of $24 million.

The following tables show production and average sales prices received by our operating divisions for 2016, 2015 and 2014:

	2016								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b] ..	26.4	41.84	537.1	2.20	11.3	14.77	127.3	55	19.29
Northern[c] ...	6.8	36.01	512.4	1.90	13.1	14.75	105.3	45	13.40
Total......	33.2	40.65	1,049.5	2.05	24.4	14.76	232.6	100%	16.63

	2015								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b] ..	33.4	47.33	573.8	2.52	14.9	13.13	143.9	58	22.40
Northern[c] ...	8.2	39.45	496.0	2.06	13.1	15.12	104.0	42	14.85
Total......	41.6	45.77	1,069.8	2.31	28.0	14.06	247.9	100%	19.23

	2014								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b] ..	35.3	91.15	580.7	4.20	16.9	32.18	148.9	58	41.62
Northern[c] ...	7.0	80.15	514.3	4.08	16.2	29.56	108.9	42	28.81
Total......	42.3	89.41	1,095.0	4.14	33.1	30.95	257.8	100%	36.21

(a) Average sales prices exclude gains (losses) on derivatives.

(b) Our Southern Division includes the Eagle Ford and Anadarko Basin liquids plays and the Haynesville/Bossier and Barnett (prior to October 31, 2016) natural gas shale plays. The Eagle Ford Shale accounted for approximately 33% of our estimated proved reserves by volume as of December 31, 2016. Eagle Ford Shale production for 2016, 2015 and 2014 was 35.4 mmboe, 38.5 mmboe and 35.4 mmboe, respectively.

(c) Our Northern Division includes the Utica and Powder River liquids plays and the Marcellus natural gas play. The Utica Shale accounted for approximately 22% of our estimated proved reserves by volume as of December 31, 2016. Utica Shale production for 2016, 2015 and 2014 was 46.7 mmboe, 43.8 mmboe and 26.6 mmboe, respectively. The Marcellus Shale accounted for approximately 18% of our estimated proved reserves by volume as of December 31, 2016. Marcellus Shale production for 2016, 2015 and 2014 was 50.0 mmboe, 49.7 mmboe and 74.7 mmboe, respectively.

Our average daily production of 635 mboe for 2016 consisted of approximately 90,800 bbls of oil (14% on an oil equivalent basis), approximately 2.9 bcf of natural gas (75% on an oil equivalent basis) and approximately 66,700 bbls of NGL (11% on an oil equivalent basis). Oil production decreased by 20% year over year primarily as a result of the sale of certain of our Mid-Continent assets in 2016 and 2015 as well as a significant reduction in drilling activity. Natural gas production decreased by 2% and NGL production decreased by 13%.

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

	Years Ended December 31,		
	2016	2015	2014
Oil	35	40	40
Natural gas	56	52	49
NGL	9	8	11
Total	100%	100%	100%

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses and exclude depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our marketing, gathering and compression assets. We recognized $4.584 billion in marketing, gathering and compression revenues in 2016, of which $146 million related to cash proceeds from the sale of a long-term natural gas supply contract to a third party, offset by the reversal of cumulative unrealized gains of $297 million associated with the natural gas supply contract, with corresponding expenses of $4.778 billion, for a net loss of $194 million. This compares to revenues of $7.373 billion, of which $296 million related to unrealized gains on the fair value of our supply contract derivative, with corresponding expenses of $7.130 billion, for a net margin of $243 million in 2015 and revenues of $12.225 billion, expenses of $12.236 billion and a net loss before depreciation of $11 million in 2014. Revenues and expenses decreased in 2016 compared to 2015 and 2014 primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations. The margin increase in 2015 as compared to 2014 was primarily the result of an unrealized gain on the fair value adjustment on our supply contract derivatives, partially offset by cost increases on certain sales contracts with third parties entered into to help meet certain of our oil pipeline and other commitments and by lower compression margin as a result of the sale of a significant portion of our compression assets in 2014 and 2015.

Oilfield Services Revenues and Expenses. Our oilfield services consisted of third-party revenues and expenses related to our former oilfield services operations and excluded depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our oilfield services assets in 2014. Chesapeake recognized revenues of $546 million, expenses of $431 million with a net margin before depreciation of $115 million in 2014. As a result of the spin-off of our oilfield services business in June 2014, we did not have oilfield services revenues and expenses in 2016 and 2015.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $710 million in 2016, compared to $1.046 billion in 2015 and $1.208 billion in 2014. On a unit-of-production basis, production expenses were $3.05 per boe in 2016 compared to $4.22 per boe in 2015 and $4.69 per boe in 2014. The absolute and per unit decrease in 2016 was primarily the result of a reduction in repair and maintenance expenses as well as operating efficiencies across most of our operating areas. Production expenses in 2016, 2015 and 2014 included approximately $44 million, $104 million and $157 million, or $0.19, $0.42 and $0.61 per boe, respectively, associated with VPP production volumes. In connection with certain 2016 divestitures, we purchased the remaining oil and natural gas interests previously sold in connection with five of our VPPs, and a majority of these repurchased oil and natural gas interests were subsequently sold. In addition, one of our VPPs expired in 2015. 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.

The following table shows our production expenses (excluding ad valorem taxes) by operating division and our ad valorem tax expenses for 2016, 2015 and 2014:

	2016		2015		2014	
	Production Expenses	$/boe	Production Expenses	$/boe	Production Expenses	$/boe
	($ in millions, except per unit)					
Southern	$ 498	3.92	$ 771	5.36	$ 882	5.92
Northern	157	1.49	188	1.81	229	2.10
	655	2.81	959	3.87	1,111	4.31
Ad valorem tax	55	0.24	87	0.35	97	0.38
Total	$ 710	3.05	$ 1,046	4.22	$ 1,208	4.69

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $1.855 billion in 2016 compared to $2.119 billion in 2015 and $2.174 billion in 2014. On a unit-of-production basis, gathering, processing and transportation expenses were $7.98 per boe in 2016 compared to $8.55 per boe in 2015 and $8.43 per boe in 2014. Certain of our gathering agreements required us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. These fees amounted to $171 million in 2015 and $120 million in 2014, or $0.69 and $0.47 per boe, respectively. We were not required to pay any shortfall fees in 2016.

A summary of oil, natural gas and NGL gathering, processing and transportation expenses by product is shown below.

	Years Ended December 31,		
	2016	2015	2014
Oil ($ per bbl)	$ 3.61	$ 3.38	$ 2.86
Natural gas ($ per mcf)	$ 1.47	$ 1.66	$ 1.68
NGL ($ per bbl)	$ 7.83	$ 7.37	$ 6.59

Production Taxes. Production taxes were $74 million in 2016 compared to $99 million in 2015 and $232 million in 2014. On a unit-of-production basis, production taxes were $0.32 per boe in 2016 compared to $0.40 per boe in 2015 and $0.90 per boe in 2014. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in 2016 and 2015 was primarily due to lower prices received for oil, natural gas and NGL. Production taxes in 2016, 2015 and 2014 included approximately $3 million $2 million and $16 million respectively, or $0.01, $0.01 and $0.06 per boe, respectively, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses were $240 million in 2016, $235 million in 2015 and $322 million in 2014, or $1.03, $0.95 and $1.25 per boe, respectively. Lower general and administrative expenses in 2016 and 2015 were due primarily to reduced overhead as a result of our workforce reduction in the 2015 third quarter and our continuing efforts to reduce other administrative expenses, as well as the spin-off of our oilfield services business in June 2014.

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $148 million, $196 million and $230 million of internal costs in 2016, 2015 and 2014, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded $6 million, $36 million and $7 million in 2016, 2015 and 2014, respectively, for restructuring and other termination costs. The 2016 amount was primarily related to the reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary and the reductions of workforce in connection with certain of our divestitures. In 2015, we reduced our workforce by approximately 15% as part of an overall plan to reduce costs and better align our workforce with the needs of our business and current oil and natural gas commodity prices. In connection with the reduction, we incurred a total charge of approximately $55 million for one-time termination benefits, all of which were paid in cash in the fourth quarter of 2015. Additionally, the 2015 and 2014 amounts included negative fair value adjustments to PSUs granted to former executives of the Company, which were primarily the result of a decrease in the trading price of our common stock. The 2014 expense also includes charges incurred in connection with the spin-off of our oilfield services business and senior management separations. See Note 18 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our restructuring and other termination costs.

Provision for Legal Contingencies. In 2016, 2015 and 2014, we recorded $123 million, $353 million and $234 million, respectively, for legal contingencies. The 2016 provision consists of accruals for loss contingencies primarily related to royalty claims. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of royalty claims. The 2015 amount includes $25 million related to the April 2015 resolution of litigation we were defending against the state of Michigan and $339 million related to litigation involving the early redemption of our 2019 notes. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for discussion of ongoing 2019 Notes litigation. Additionally, in 2015, we reduced our royalty provision amount from $119 million to $109 million to reflect the amount paid in 2015 to settle litigation with Oklahoma royalty owners, net of claimants that opted out. In 2014, we accrued $134 million of loss contingencies related to royalty claims, and a $100 million loss contingency for litigation regarding our 2019 Notes litigation.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $1.003 billion, $2.099 billion and $2.683 billion in 2016, 2015 and 2014, respectively. The average DD&A rate per boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $4.31, $8.47 and $10.41 per boe in 2016, 2015 and 2014, respectively. The absolute and per unit decrease in 2016 was the result of a lower amortization base, which is due to the 2016 and 2015 impairments of our oil and natural gas properties. The absolute and per unit decrease in 2015 was the result of a lower amortization base as a result of our impairment of oil and gas properties in 2015 and a reduction in our estimated future development costs as a result of drilling efficiencies and a forecasted reduction in our future capital plans, partially offset by an approximate 39% reduction in our reserve base driven primarily by lower prices used in calculating our estimated reserves.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $104 million in 2016 compared to $130 million in 2015 and $232 million in 2014. On a unit-of-production basis, depreciation and amortization of other assets was $0.45 per boe in 2016 compared to $0.53 per boe in 2015 and $0.90 per boe in 2014. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. In June 2014, we completed the spin-off of our oilfield services business and, therefore, did not incur oilfield services depreciation expense in 2016 or 2015 and will not incur this expense in future periods. In 2014, to the extent company-owned oilfield services equipment was used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) was capitalized in oil and natural gas properties as drilling and completion costs. The following table shows depreciation expense by asset class for the years ended December 31, 2016, 2015 and 2014 and the estimated useful lives of these assets.

	Years Ended December 31,			Estimated Useful Life
	2016	2015	2014	
	($ in millions)			(in years)
Buildings and improvements	$ 38	$ 39	$ 42	10 – 39
Natural gas compressors[(a)]	24	38	37	3 – 20
Computers and office equipment	20	22	32	3 – 7
Vehicles	3	10	24	0 – 7
Natural gas gathering systems and treating plants[(a)]	7	11	12	20
Oilfield services equipment[(b)]	—	—	74	3 – 15
Other	12	10	11	2 – 20
Total depreciation and amortization of other assets	$ 104	$ 130	$ 232	

(a) Included in our marketing, gathering and compression operating segment.

(b) Included in our former oilfield services operating segment.

Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. For 2016 and 2015, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments of the carrying value of our oil and natural gas properties of $2.564 billion and $18.238 billion, respectively.

As of December 31, 2016, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $4.405 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, gathering, processing, transportation and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of December 31, 2016 were $42.75 per bbl of oil and $2.49 per mcf of natural gas, before price differential adjustments.

Impairments of Fixed Assets and Other. In 2016, 2015 and 2014, we recognized $838 million, $194 million and $88 million, respectively, of fixed asset impairment losses and other charges. 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. In connection with this disposition, we recognized $361 million of charges related to the termination of natural gas gathering and transportation agreements. We also recognized an impairment charge of $284 million in 2016 related to other fixed assets sold in the divestiture. Also 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. The 2015 amount consisted primarily of a $70 million settlement charge for a net acreage maintenance obligation to Total S.A. in our Barnett Shale joint venture, a $47 million loss contingency related to contract disputes, a $21 million impairment related to the sale of third-party rental compressors, a $22 million impairment of a note receivable and $7 million of charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices. The 2014 amount consisted primarily of a $22 million charge for our Barnett Shale joint venture net acreage shortfall with Total and $64 million of impairments related to a gathering system, drilling rigs, natural gas compressors and buildings and land.

Net (Gains) Losses on Sales of Fixed Assets. In 2016, net gains on sales of fixed assets were $12 million compared to net losses of $4 million in 2015 and net gains of $199 million in 2014. The 2016 and 2015 amounts primarily related to the sale of gathering systems, buildings, land and other property and equipment. The 2014 amount primarily related to the sale of natural gas compressors and crude hauling assets. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our net (gains) losses on sales of fixed assets.

Interest Expense. Interest expense was $296 million in 2016 compared to $317 million in 2015 and $89 million in 2014 as follows:

	Years Ended December 31,		
	2016	2015	2014
		($ in millions)	
Interest expense on senior notes	$ 588	$ 682	$ 704
Interest expense on term loan	46	—	36
Amortization of loan discount, issuance costs and other	33	62	42
Amortization of premium associated with troubled debt restructuring	(165)	(3)	—
Interest expense on revolving credit facilities	35	12	28
Realized gains on interest rate derivatives[a]	(11)	(6)	(12)
Unrealized (gains) losses on interest rate derivatives[b]	21	(6)	(72)
Capitalized interest	(251)	(424)	(637)
Total interest expense	$ 296	$ 317	$ 89
Average senior notes borrowings	$ 8,749	$ 11,705	11,653
Average credit facilities borrowings	$ 195	$ —	306
Average term loan borrowings	$ 537	$ —	625

(a) Includes settlements related to the interest accrual for the period and the effect of (gains) losses on early-terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(b) Includes changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

The 2016 and 2015 decreases in capitalized interest resulted from lower average balances of unproved oil and natural gas properties, the primary asset on which interest is capitalized. The 2016 decrease in interest expense on senior notes is due to the decrease in the average outstanding principal amount of senior notes. The 2016 increase in the amortization of premium associated with troubled debt restructuring is due to a full year of amortization on our second lien notes. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our debt refinancing. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.18 per boe in 2016 compared to $1.30 per boe in 2015 and $0.63 per boe in 2014.

Losses on Investments. Losses on investments were $8 million, $96 million and $75 million in 2016, 2015 and 2014, respectively. In 2016, the losses were primarily related to our equity investment in Sundrop Fuels, Inc. (Sundrop). Losses on investments in 2015 and 2014 were primarily related to our equity investments in FTS International, Inc. (FTS) and Sundrop. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

Impairment of Investments. In 2016, 2015 and 2014, we recognized impairments of investments of $119 million, $53 million and $5 million, respectively. The 2016 amount consisted of an other-than-temporary impairment of our Sundrop investment. The 2015 amount consisted of an other-than-temporary impairment of our FTS investment due to the extended decrease in the oil and natural gas pricing environment. The 2014 amount related to an other miscellaneous investment. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

Net Gain (Loss) on Sales of Investments. In 2016, we recorded a $10 million net loss on the sale of an investment compared to a $67 million net gain on the sales of investments in 2014. In 2016, we sold certain of our mineral interests and assigned our partnership interest in Mineral Acquisition Company I, L.P. to KKR Royalty Aggregator LLC. As a result of the transaction, we wrote off our equity investment and recognized a $10 million loss. In 2014, we sold all of our interest in Chaparral Energy, Inc. for net cash proceeds of $209 million and recorded a $73 million gain related to the sale. In addition, we sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction.

Gains (Losses) on Purchases or Exchanges of Debt. In 2016 and 2015, we recorded gains of $236 million and $279 million, respectively, on purchases of debt and we recorded losses on purchases of debt of $197 million in 2014.

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 $1.451 billion principal amount of our senior notes and $708 million principal amount of our contingent convertible senior notes for an aggregate $2.078 billion pursuant to tender offers. Also, in 2016, we repurchased in the open market approximately $325 million principal amount of our senior notes for $300 million and $141 million principal amount of our contingent convertible senior notes for $86 million. Additionally, in 2016, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of our common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of our common stock. We recorded an aggregate gain of $236 million associated with these debt repurchases and exchanges.

In December 2015, we privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 for certain outstanding senior unsecured notes and contingent convertible notes. For certain of the notes exchanged, we are accounting for these exchanges as a trouble debt restructuring (TDR). For exchanges classified as TDR, if the future undiscounted cash flows of the newly issued debt are less than the net carrying value of the original debt, a gain is recorded for the difference and the carrying value of the newly issued debt is adjusted to the future undiscounted cash flow amount and no interest expense is recorded going forward. For the remaining TDR exchanges, where the future undiscounted cash flows are greater than the net carrying value of the original debt, no gain is recognized and a new effective interest rate is established. Accordingly, we recognized a gain of $304 million in our consolidated statement of operations. Direct costs incurred for $29 million related to the notes exchange were also recognized. Additionally, we purchased in the open market approximately $119 million aggregate principal amount of our 3.25% Senior Notes due 2016 for cash. We recorded a gain of approximately $5 million associated with the repurchase.

In December 2014, we entered into a new five-year $4.0 billion senior revolving credit facility to use for general corporate purposes. That credit facility replaced our then-existing $4.0 billion senior secured revolving credit facility that was scheduled to mature in December 2015. We recognized a loss of approximately $2 million in extinguishment costs related to former lenders under the terminated facility who were not continuing under the new facility. In 2014, we repaid the borrowings under and terminated our $2.0 billion term loan credit facility due 2017 and recorded a loss of approximately $90 million. Also in 2014, we purchased and redeemed $1.265 billion in aggregate principal amount of our 9.5% Senior Notes due 2015. We recorded a loss of approximately $99 million associated with the purchase and redemption. In addition, we redeemed $97 million in principal amount of our 6.875% Senior Notes due 2018 at par. We recorded a loss of approximately $6 million associated with the redemption.

Other Income. Other income was $19 million in 2016 compared to $8 million in 2015 and $22 million in 2014. The 2016 other income consisted primarily of $2 million of interest income and $17 million of miscellaneous income. The 2015 income consisted of $6 million of interest income and $2 million of miscellaneous income. The 2014 other income consisted of $3 million of interest income and $19 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $190 million in 2016, an income tax benefit of $4.463 billion in 2015 and income tax expense of $1.144 billion in 2014. Our effective income tax rate was 4.1% in 2016 compared to 23.4% in 2015 and 35.8% in 2014. The decrease in the effective income tax rate from 2015 to 2016 is primarily due to the tax benefit at expected rates being offset by a valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of income tax expense (benefit).

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $2 million, $50 million and $139 million in 2016, 2015 and 2014, respectively. The 2016 amount was attributable to the Chesapeake Granite Wash Trust (the Trust). The 2015 amount was primarily related to dividends paid on preferred stock of our CHK C-T subsidiary. The decrease from 2015 to 2016 is due to the repurchase of all of the preferred shares of CHK C-T from third-party shareholders in August 2015. The 2014 amount included income related to the Trust as well as dividends paid on preferred stock of our CHK C-T and CHK Utica subsidiaries. The decrease from 2014 to 2015 is primarily due to the repurchase of all of the outstanding preferred shares of CHK Utica and CHK C-T from third-party preferred shareholders in July 2014 and August 2015, respectively. See Notes 8 and 15 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of these entities.

Application of Critical Accounting Policies

Readers of this report and users of the information contained in it should be aware that certain events may impact our financial results based on the accounting policies in place. The three policies we consider to be most significant to our financial statements are discussed below. The Company's management has discussed each critical accounting policy with the Audit Committee of the Company's Board of Directors.

The selection and application of accounting policies is an important process that changes as our business evolves and accounting rules are refined. Accounting rules generally do not involve a selection among alternatives, but rather they provide for the interpretation of existing rules and the use of judgment in applying guidance to the specific set of circumstances existing in our business.

Oil and Natural Gas Properties. The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. Chesapeake follows the full cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not capitalize any costs related to production, general corporate overhead or similar activities.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, our financial statements differ from those of companies that apply the successful efforts method since we generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation, depletion and amortization rate, and we do not have exploration expenses that successful efforts companies frequently have.

Under the full cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless these sales involve a significant change in proved reserves and significantly alter the relationship between costs and proved reserves, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant.

We review the carrying value of our oil and natural gas properties under the SEC's full cost accounting rules on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for oil and natural gas cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating estimated future net revenues, current prices are calculated as the unweighted arithmetic average of oil and natural gas prices on the first day of each month within the 12-month period prior to the ending date of the quarterly period. Costs used are those as of the end of the applicable quarterly period. These prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives designated as cash flow hedges.

Two primary factors impacting this test are reserve levels and oil and natural gas prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of oil and natural gas reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. 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 full cost method of accounting.

Derivatives. Chesapeake uses commodity price and financial risk management instruments to mitigate a portion of our exposure to price fluctuations in oil, natural gas and NGL prices, changes in interest rates and foreign exchange rates. Gains and losses on derivative contracts are reported as a component of the related transaction. Results of commodity derivative contracts are reflected in oil, natural gas and NGL sales and results of interest rate and foreign exchange rate derivative contracts are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying, or not elected, for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil, natural gas and NGL sales or interest expense. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative is 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 statements of cash flows.

Accounting guidance for derivative instruments and hedging activities establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheets as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as oil, natural gas and NGL cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings as oil, natural gas and NGL sales. Any change in the fair value resulting from ineffectiveness is recognized immediately in oil, natural gas and NGL sales. For interest rate derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings as interest expense. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See *Derivative Activities* above and Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information regarding our derivative activities.

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.

Due to the volatility of oil, natural gas and NGL prices and, to a lesser extent, interest rates and foreign exchange rates, the Company's financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2016 and 2015, the fair values of our derivatives were net liabilities of $577 million and net assets of $512 million, respectively.

Income Taxes. The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of both federal and state taxing jurisdictions. Income taxes are accounted for using the asset and liability approach. The Company has recognized deferred tax assets and liabilities for temporary differences between tax and book basis, tax credit carryforwards and net operating loss carryforwards. 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 some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider the preponderance of evidence 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. As of December 31, 2016 and 2015, we had deferred tax assets of $4.690 billion and $4.122 billion, respectively, upon which we had a valuation allowance of $4.389 billion and $2.949 billion, respectively. The valuation allowance as of December 31, 2016 and 2015 was recorded against our net deferred tax assets. We have concluded that these deferred tax assets are not more likely than not to be realized.

The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest related to these uncertain tax positions which is recognized in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. Additional information about uncertain tax positions appears in Note 6 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 7 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.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the Exchange Act). Forward-looking statements give our current expectations or forecasts of future events. They include expected oil, natural gas and NGL production and future expenses, estimated operating costs, assumptions regarding future oil, natural gas and NGL prices, planned drilling activity, estimates of future drilling and completion and other capital expenditures (including the use of joint venture drilling carries), potential future write-downs of our oil and natural gas assets, anticipated sales, and the adequacy of our provisions for legal contingencies, as well as statements concerning anticipated cash flow and liquidity, ability to comply with financial maintenance covenants and meet contractual cash commitments to third parties, debt repurchases, operating and capital efficiencies, business strategy, the effect of our remediation plan for a material weakness, and other plans and objectives for future operations. Disclosures concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under *Risk Factors i*n Item 1A of Part I of this report and include:

- the volatility of oil, natural gas and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- our inability to access the capital markets on favorable terms;
- the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations;
- our credit rating requiring us to post more collateral under certain commercial arrangements;
- write-downs of our oil and natural gas asset carrying values due to low commodity prices;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- commodity derivative activities resulting in lower prices realized on oil, natural gas and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- charges incurred in response to market conditions and in connection with our ongoing actions to reduce financial leverage and complexity;
- drilling and operating risks and resulting liabilities;
- effects of environmental protection laws and regulation on our business;
- legislative and regulatory initiatives further regulating hydraulic fracturing;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- impacts of potential legislative and regulatory actions addressing climate change;
- federal and state tax proposals affecting our industry;
- potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations;
- competition in the oil and gas exploration and production industry;
- a deterioration in general economic, business or industry conditions;
- negative public perceptions of our industry;

- limited control over properties we do not operate;
- pipeline and gathering system capacity constraints and transportation interruptions;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- potential challenges by SSE's former creditors of our spin-off of in connection with SSE's recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code;
- an interruption in operations at our headquarters due to a catastrophic event;
- the continuation of suspended dividend payments on our common stock;
- the effectiveness of our remediation plan for a material weakness;
- certain anti-takeover provisions that affect shareholder rights; and
- our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, and we undertake no obligation to update this information except as required by applicable law. We urge you to carefully review and consider the disclosures made in this report and our other filings with the SEC that attempt to advise interested parties of the risks and factors that may affect our business.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Oil, Natural Gas and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective prices to be received for our share of production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse oil, natural gas and NGL price changes is to hedge into strengthening oil and natural gas futures markets when prices reach levels that management believes are unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends.

We use derivative instruments to achieve our risk management objectives, including swaps, collars and options. All of these are described in more detail below. We typically use swaps and collars for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility.

We determine the volume potentially subject to derivative contracts by reviewing our overall estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not enter into derivative contracts for volumes in excess of our share of forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be reversed. The actual fixed price on our derivative instruments is derived from the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our commodity derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price payment, resulting in a net amount due to or from the counterparty.

We review our derivative positions continuously and if future market conditions change and prices are at levels we believe could jeopardize the effectiveness of a position, we will mitigate this risk by either negotiating a cash settlement with our counterparty, restructuring the position or entering into a new trade that effectively reverses the current position. The factors we consider in closing or restructuring a position before the settlement date are identical to those we review when deciding to enter into the original derivative position. Gains or losses related to closed positions will be recognized in the month of related production based on the terms specified in the original contract.

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our commodity hedging arrangements which require counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the fair value measurements associated with our derivatives.

As of December 31, 2016, our oil, natural gas and NGL derivative instruments consisted of the following:

- *Swaps*: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- *Options*: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty the excess on sold call options, and Chesapeake receives the excess on bought call options. If the market price settles below the fixed price of the call options, no payment is due from either party.
- *Collars*: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

As of December 31, 2016, we had the following open oil, natural gas and NGL derivative instruments:

	Volume	Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps:						
Short-term	23	$ 50.19	$ —	$ —	$ —	$ (140)
Call Options (sold):						
Short-term	5	$ —	$ 83.50	$ —	$ —	(1)
Total Oil						$ (141)
	(tbtu)	($ per mmbtu)				
Natural Gas:						
Swaps:						
Short-term	599	$ 3.07	$ —	$ —	$ —	$ (336)
Long-term	120	$ 3.13	$ —	$ —	$ —	(13)
Collars:						
Short-term	23	$ —	$ 3.48	$ 3.00	$ —	(8)
Long-term	37	$ —	$ 3.25	$ 3.00	$ —	(1)
Call Options (sold):						
Short-term	48	$ —	$ 9.43	$ —	$ —	—
Long-term	66	$ —	$ 12.00	$ —	$ —	—
Basis Protection Swaps:						
Short-term	30	$ —	$ —	$ —	$ (0.11)	(4)
Long-term	1	$ —	$ —	$ —	$ (0.98)	(1)
Total Natural Gas						$ (363)
	(mmgal)	($ per mgal)				
NGL:						
Ethane Swaps:						
Short-term	53	$ 0.28	$ —	$ —	$ —	$ —
Total NGL						$ —
Total Oil, Natural Gas and NGL						$ (504)

In addition to the open derivative positions disclosed above, as of December 31, 2016, we had nominal derivative gains related to settled contracts for future production periods that will be recorded within oil, natural gas and NGL sales as realized gains (losses) on derivatives once they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production, based on the terms specified in the original contract as noted below.

	December 31, 2016
	($ in millions)
Short-term	$ 82
Long-term	(82)
Total	$ —

The table below reconciles the changes in fair value of our oil and natural gas derivatives during 2016. Of the $504 million fair value liability as of December 31, 2016, a $489 million liability relates to contracts maturing in the next 12 months and a $15 million liability relates to contracts maturing after 12 months. All open derivative instruments as of December 31, 2016 are expected to mature by December 31, 2022.

	December 31, 2016
	($ in millions)
Fair value of contracts outstanding, as of January 1, 2016	$ 267
Change in fair value of contracts	(546)
Contracts realized or otherwise settled	(230)
Fair value of contracts closed	5
Fair value of contracts outstanding, as of December 31, 2016	$ (504)

The change in oil and natural gas prices during 2016 decreased the asset related to our derivative instruments by $546 million. This unrealized loss is recorded in oil, natural gas and NGL sales. We settled contracts in 2016 that were in an asset position for $230 million. We terminated contracts that were in a liability position for $5 million. Realized gains and losses will be recorded in oil, natural gas and NGL sales in the month of related production.

Interest Rate Derivatives

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates, using the earliest demand repurchase date for contingent convertible senior notes. As of December 31, 2016, we had total debt of $9.989 billion, including $8.109 billion of fixed rate debt at interest rates averaging 6.66% and $1.880 billion of floating rate debt at an interest rate of 7.62%.

	Years of Maturity						
	2017	2018	2019	2020	2021	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$ 506	$ 264	$ —	$ 1,061	$ 820	$ 5,458	$ 8,109
Average interest rate	5.47%	3.46%	—%	6.68%	5.88%	7.03%	6.66%
Debt – variable rate	$ —	$ —	$ 380	$ —	$ 1,500	$ —	$ 1,880
Average interest rate	—%	—%	4.13%	—%	8.50%	—%	7.62%

(a) This amount does not include the premium, discount and deferred financing costs included in debt of $449 million and interest rate derivatives of $3 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving credit facility, term loan and our floating rate senior notes. All of our other indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

From time to time, we enter into interest rate derivatives, including fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes and floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our revolving credit facility borrowings. As of December 31, 2016, there were no interest rate derivatives outstanding.

As of December 31, 2016, we had $14 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains or losses once they are transferred from our senior note liability or within interest expense as unrealized gains or losses over the remaining seven-year term of our related senior notes.

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

Foreign Currency Derivatives

In December 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the senior notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. In 2016, in connection with our tender offers, we retired €56 million in aggregate principal amount of our 6.25% Euro-denominated Senior Notes due 2017, and we simultaneously unwound the cross currency swaps for the same principal amount at a cost of $13 million. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €8 million and we pay the counterparties $12 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €246 million and we will pay 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. Through the cross currency swaps, we have eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the consolidated balance sheets as liabilities of $73 million and $52 million as of December 31, 2016 and 2015, respectively. The euro-denominated debt in long-term debt has been adjusted to $258 million as of December 31, 2016, using an exchange rate of $1.0517 to €1.00.

Supply Contract Derivatives

As discussed in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report, we enter into supply contracts in the normal course of business under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas thereby creating an embedded derivative requiring bifurcation. The prices of the products other than natural gas are unobservable. We engage an independent third-party valuation firm to value these supply contracts. The products being valued other than natural gas are sensitive to pricing fluctuations and some of these fluctuations could be material. Changes to the value of these contracts are recorded as mark-to-market adjustments to marketing, gathering and compression revenues in our consolidated financial statements.

ITEM 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended).

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.

Under the supervision and with the participation of our management, including the CEO and the CFO, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2016 using the criteria established in "Internal Control-Integrated Framework" (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis.

We did not effectively design and maintain controls over the review of the valuation of proved oil and natural gas properties and the accuracy of impairment of oil and natural gas properties. Specifically, the review of the initial configuration of a newly implemented tool used to calculate basis price differentials did not detect an error in the formula in the calculations, and the manual interface control to agree data used in the tool to the general ledger was not designed to validate the data at an appropriately disaggregated level.

The control deficiency did not result in a material misstatement to the Company's consolidated financial statements for the year ended December 31, 2016. However, the control deficiency could result in misstatements of the aforementioned account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that this control deficiency constitutes a material weakness.

Because of this material weakness, management concluded that the Company did not maintain effective internal control over financial reporting as of December 31, 2016.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report, which appears herein.

/s/ ROBERT D. LAWLER

Robert D. Lawler
President and Chief Executive Officer

/s/ DOMENIC J. DELL'OSSO, JR.

Domenic J. Dell'Osso, Jr.
Executive Vice President and Chief Financial Officer

March 3, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Chesapeake Energy Corporation

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) because a material weakness in internal control over financial reporting related to the review of the valuation of proved oil and natural gas properties and the accuracy of impairment of oil and natural gas properties existed as of that date. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in the accompanying Management's Report on Internal Control over Financial Reporting. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2016 consolidated financial statements, and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements. The Company's management is responsible for these 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 referred to above. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for debt issuance costs in 2016.

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
March 3, 2017

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$ 882	$ 825
Accounts receivable, net	1,057	1,129
Short-term derivative assets	—	366
Other current assets	203	160
Total Current Assets	2,142	2,480
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full cost accounting:		
Proved oil and natural gas properties ($488 and $488 attributable to our VIE)	66,451	63,843
Unproved properties	4,802	6,798
Other property and equipment	2,053	2,927
Total Property and Equipment, at Cost	73,306	73,568
Less: accumulated depreciation, depletion and amortization (($458) and ($428) attributable to our VIE)	(62,726)	(59,365)
Property and equipment held for sale, net	29	95
Total Property and Equipment, Net	10,609	14,298
LONG-TERM ASSETS:		
Long-term derivative assets	—	246
Other long-term assets	277	290
TOTAL ASSETS	$ 13,028	$ 17,314

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

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

	December 31,	
	2016	2015
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 672	$ 944
Current maturities of long-term debt, net	503	381
Accrued interest	113	101
Short-term derivative liabilities	562	40
Other current liabilities ($3 and $8 attributable to our VIE)	1,798	2,219
Total Current Liabilities	3,648	3,685
LONG-TERM LIABILITIES:		
Long-term debt, net	9,938	10,311
Long-term derivative liabilities	15	60
Asset retirement obligations, net of current portion	247	452
Other long-term liabilities	383	409
Total Long-Term Liabilities	10,583	11,232
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 5,839,506 and 7,251,515 shares outstanding	1,771	3,062
Common stock, $0.01 par value, 1,500,000,000 and 1,000,000,000 shares authorized: 896,279,353 and 664,795,509 shares issued	9	7
Additional paid-in capital	14,486	12,403
Accumulated deficit	(17,603)	(13,202)
Accumulated other comprehensive loss	(96)	(99)
Less: treasury stock, at cost; 1,220,504 and 1,437,724 common shares	(27)	(33)
Total Chesapeake Stockholders' Equity (Deficit)	(1,460)	2,138
Noncontrolling interests	257	259
Total Equity (Deficit)	(1,203)	2,397
TOTAL LIABILITIES AND EQUITY	$ 13,028	$ 17,314

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,		
	2016	2015	2014
	($ in million except per share data)		
REVENUES:			
Oil, natural gas and NGL	$ 3,288	$ 5,391	$ 10,354
Marketing, gathering and compression	4,584	7,373	12,225
Oilfield services	—	—	546
Total Revenues	7,872	12,764	23,125
OPERATING EXPENSES:			
Oil, natural gas and NGL production	710	1,046	1,208
Oil, natural gas and NGL gathering, processing and transportation	1,855	2,119	2,174
Production taxes	74	99	232
Marketing, gathering and compression	4,778	7,130	12,236
Oilfield services	—	—	431
General and administrative	240	235	322
Restructuring and other termination costs	6	36	7
Provision for legal contingencies	123	353	234
Oil, natural gas and NGL depreciation, depletion and amortization	1,003	2,099	2,683
Depreciation and amortization of other assets	104	130	232
Impairment of oil and natural gas properties	2,564	18,238	—
Impairments of fixed assets and other	838	194	88
Net (gains) losses on sales of fixed assets	(12)	4	(199)
Total Operating Expenses	12,283	31,683	19,648
INCOME (LOSS) FROM OPERATIONS	(4,411)	(18,919)	3,477
OTHER INCOME (EXPENSE):			
Interest expense	(296)	(317)	(89)
Losses on investments	(8)	(96)	(75)
Impairments of investments	(119)	(53)	(5)
Net gain (loss) on sales of investments	(10)	—	67
Gains (losses) on purchases or exchanges of debt	236	279	(197)
Other income	19	8	22
Total Other Expense	(178)	(179)	(277)
INCOME (LOSS) BEFORE INCOME TAXES	(4,589)	(19,098)	3,200
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	(19)	(36)	47
Deferred income taxes	(171)	(4,427)	1,097
Total Income Tax Expense (Benefit)	(190)	(4,463)	1,144
NET INCOME (LOSS)	(4,399)	(14,635)	2,056
Net income attributable to noncontrolling interests	(2)	(50)	(139)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(4,401)	(14,685)	1,917
Preferred stock dividends	(97)	(171)	(171)
Loss on exchange of preferred stock	(428)	—	—
Repurchase of preferred shares of CHK Utica	—	—	(447)
Earnings allocated to participating securities	—	—	(26)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (4,926)	$ (14,856)	$ 1,273
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ (6.45)	$ (22.43)	$ 1.93
Diluted	$ (6.45)	$ (22.43)	$ 1.87
CASH DIVIDEND DECLARED PER COMMON SHARE	$ —	$ 0.0875	$ 0.35
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	764	662	659
Diluted	764	662	772

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,		
	2016	2015	2014
		($ in millions)	
NET INCOME (LOSS)	$ (4,399)	$ (14,635)	$ 2,056
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Unrealized gains (losses) on derivative instruments, net of income tax expense (benefit) of ($14), $12 and $0	(13)	20	1
Reclassification of losses on settled derivative instruments, net of income tax expense of $18, $15 and $14	16	24	23
Reclassification of (gains) losses on investment, net of income tax expense (benefit) of $0, $0 and ($3)	—	—	(5)
Other Comprehensive Income (Loss)	3	44	19
COMPREHENSIVE INCOME (LOSS)	(4,396)	(14,591)	2,075
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(2)	(50)	(139)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (4,398)	$ (14,641)	$ 1,936

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,		
	2016	2015	2014
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET (INCOME) LOSS	$ (4,399)	$ (14,635)	$ 2,056
ADJUSTMENTS TO RECONCILE NET LOSS TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	1,107	2,229	2,915
Deferred income tax expense (benefit)	(171)	(4,427)	1,097
Derivative (gains) losses, net	739	(932)	(1,102)
Cash receipts (payments) on derivative settlements, net	448	1,123	(253)
Stock-based compensation	52	78	59
Impairment of oil and natural gas properties	2,564	18,238	—
Net (gains) losses on sales of fixed assets	(12)	4	(199)
Renegotiation of natural gas gathering contracts	(115)	—	—
Impairments of fixed assets and other	467	175	58
Losses on investments	8	96	75
Net (gain) loss on sales of investment	10	—	(67)
Impairments of investments	119	53	5
(Gains) losses on purchases or exchanges of debt	(236)	(304)	63
Restructuring and other termination costs	3	(14)	(15)
Provision for legal contingencies	87	340	234
Other	(143)	244	220
(Increase) decrease in accounts receivable and other assets	21	1,186	(21)
Decrease in accounts payable, accrued liabilities and other	(753)	(2,220)	(491)
Net Cash Provided By (Used In) Operating Activities	(204)	1,234	4,634
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(1,295)	(3,095)	(4,581)
Acquisitions of proved and unproved properties	(788)	(533)	(1,311)
Proceeds from divestitures of proved and unproved properties	1,406	189	5,813
Additions to other property and equipment	(37)	(143)	(726)
Proceeds from sales of other property and equipment	131	89	1,003
Cash paid for title defects	(69)	—	—
Additions to investments	—	(1)	—
Proceeds from sales of investments	—	—	239
Decrease in restricted cash	—	52	37
Other	(8)	(9)	(20)
Net Cash Provided By (Used In) Investing Activities	(660)	(3,451)	454

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

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

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Cash paid to purchase debt	(2,734)	(508)	(3,362)
Proceeds from revolving credit facilities borrowings	5,146	—	7,406
Payments on revolving credit facilities borrowings	(5,146)	—	(7,788)
Proceeds from issuance of senior notes, net of discount and offering costs	2,210	—	2,966
Proceeds from issuance of term loan, net of offering costs	1,476	—	—
Proceeds from issuance of oilfield services term loan, net of issuance costs	—	—	394
Proceeds from issuance of oilfield services senior notes, net of issuance costs	—	—	494
Cash held and retained by SSE at spin-off	—	—	(8)
Cash paid for common stock dividends	—	(118)	(234)
Cash paid for preferred stock dividends	—	(171)	(171)
Cash paid on financing derivatives	—	—	(53)
Cash paid to repurchase noncontrolling interest of CHK C-T	—	(143)	—
Cash paid to repurchase preferred shares of CHK Utica	—	—	(1,254)
Distributions to noncontrolling interest owners	(10)	(85)	(173)
Other	(21)	(41)	(34)
Net Cash Provided By (Used In) Financing Activities	921	(1,066)	(1,817)
Net increase (decrease) in cash and cash equivalents	57	(3,283)	3,271
Cash and cash equivalents, beginning of period	825	4,108	837
Cash and cash equivalents, end of period	$ 882	$ 825	$ 4,108

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

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest paid, net of capitalized interest	$ 344	$ 235	$ 96
Income taxes paid, net of refunds received	$ (27)	$ 44	$ 10
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Change in accrued drilling and completion costs	$ (23)	$ (148)	$ (84)
Change in accrued acquisitions of proved and unproved properties	$ (13)	$ 55	$ (74)
Change in divested proved and unproved properties	$ 52	$ 35	$ 38
Divestiture of proved and unproved CHK C-T properties	$ —	$ 1,024	$ —
Debt exchanged for common stock	$ 471	$ —	$ —
Repurchase of noncontrolling interest in CHK C-T	$ —	$ (872)	$ —

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,		
	2016	2015	2014
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 3,062	$ 3,062	$ 3,062
Conversions of 1,412,009, 0 and 0 shares of preferred stock for common stock	(1,291)	—	—
Balance, end of period	1,771	3,062	3,062
COMMON STOCK:			
Balance, beginning of period	7	7	7
Exchange of senior notes and contingent convertible notes	1	—	—
Conversion of preferred stock	1	—	—
Balance, end of period	9	7	7
ADDITIONAL PAID-IN CAPITAL:			
Balance, beginning of period	12,403	12,531	12,446
Stock-based compensation	64	71	47
Exchange of contingent convertible notes for 55,427,782, 0 and 0 shares of common stock	241	—	—
Exchange of senior notes for 53,923,925, 0 and 0 shares of common stock	229	—	—
Conversion of preferred stock for 120,186,195, 0 and 0 shares of common stock	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	(16)	—	—
Exercise of stock options	—	—	23
Dividends on common stock	—	(59)	—
Dividends on preferred stock	—	(128)	—
Issuance costs	(5)	—	—
Increase (decrease) in tax benefit from stock-based compensation	—	(12)	15
Balance, end of period	14,486	12,403	12,531
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance, beginning of period	(13,202)	1,483	688
Net income (loss) attributable to Chesapeake	(4,401)	(14,685)	1,917
Dividends on common stock	—	—	(234)
Dividends on preferred stock	—	—	(171)
Spin-off of oilfield services business	—	—	(270)
Repurchase of preferred shares of CHK Utica	—	—	(447)
Balance, end of period	(17,603)	(13,202)	1,483
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(99)	(143)	(162)
Hedging activity	3	44	24
Investment activity	—	—	(5)
Balance, end of period	(96)	(99)	(143)

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,		
	2016	2015	2014
	($ in millions)		
TREASURY STOCK – COMMON:			
Balance, beginning of period	(33)	(37)	(46)
Purchase of 37,871, 54,493 and 34,678 shares for company benefit plans	—	(1)	(1)
Release of 255,091, 231,081 and 422,395 shares from company benefit plans	6	5	10
Balance, end of period	(27)	(33)	(37)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT)	(1,460)	2,138	16,903
NONCONTROLLING INTERESTS:			
Balance, beginning of period	259	1,302	2,145
Net income attributable to noncontrolling interests	2	50	139
Distributions to noncontrolling interest owners	(4)	(78)	(169)
Repurchase of noncontrolling interest of CHK C-T	—	(1,015)	—
Repurchase of preferred shares of CHK Utica	—	—	(807)
Deconsolidation of investments, net	—	—	(6)
Balance, end of period	257	259	1,302
TOTAL EQUITY (DEFICIT)	$ (1,203)	$ 2,397	$ 18,205

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" 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. We also own oil and natural gas marketing and compression businesses. As of December 31, 2016, we have sold substantially all of our assets associated with our natural gas gathering business, and prior to June 30, 2014, we owned an oilfield services business (see Note 13). Our operations are located onshore in the United States.

Basis of Presentation

The accompanying consolidated financial statements of Chesapeake were prepared in accordance with accounting principles generally accepted in the United States (U.S. GAAP) and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated.

Accounting Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Estimates of oil and natural gas reserves and their values, future production rates and future costs and expenses 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.

Risks and Uncertainties

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

Consolidation

Chesapeake consolidates 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 Chesapeake is the primary beneficiary. We use the equity method of accounting to record our net interests where Chesapeake has the ability to exercise significant influence through its investment. 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. See Note 14 for further discussion of our investments. Undivided interests in oil and natural gas properties are consolidated on a proportionate basis.

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 8 for further discussion of noncontrolling interests.

Variable Interest Entities

VIEs are entities that, by design, either (i) lack sufficient equity to permit the entity to finance its activities independently, or (ii) have equity holders that do not have the power to direct the activities of the entity that most significantly impact its economic performance, the obligation to absorb the entity's losses, or the right to receive the entity's residual returns. 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.

We continually monitor our consolidated VIE to determine if any events have occurred that could cause the primary beneficiary to change. See Note 15 for further discussion of VIEs.

Cash and Cash Equivalents

For purposes of the consolidated financial statements, Chesapeake considers 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 which are judged 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. During 2016, 2015 and 2014, we recognized $10 million, $4 million and $2 million of bad debt expense related to potentially uncollectible receivables. Accounts receivable as of December 31, 2016 and 2015 are detailed below.

	December 31,	
	2016	2015
	($ in millions)	
Oil, natural gas and NGL sales	$ 840	$ 696
Joint interest	156	230
Other	93	226
Allowance for doubtful accounts	(32)	(23)
Total accounts receivable, net	$ 1,057	$ 1,129

Oil and Natural Gas Properties

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with these activities and do not capitalize any costs related to production, general corporate overhead or similar activities (see *Supplementary Information – Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities*). Capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. Estimates of our proved reserves as of December 31, 2016 were prepared by an independent engineering firm and Chesapeake's internal staff. Approximately 70% by volume and 83% by value of these proved reserves estimates as of December 31, 2016 were prepared by an independent engineering firm. In addition, our internal engineers review and update our reserves on a quarterly basis.

Proceeds from the sale of oil and natural gas properties are accounted for as reductions of capitalized costs unless these sales involve a significant change in proved reserves and significantly alter the relationship between costs and proved reserves, in which case a gain or loss is recognized.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unproved properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. Unproved properties are grouped by major prospect area in circumstances where individual property costs are not significant. In addition, we analyze our unproved leasehold and transfer to proved properties that portion of our leasehold that expired in the quarter, or leasehold that is no longer part of our development strategy and will be abandoned.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2016 and the year in which the associated costs were incurred.

	Year of Acquisition				
	2016	2015	2014	Prior	Total
	($ in millions)				
Leasehold cost	$ 109	$ 99	$ 507	$ 2,956	$ 3,671
Exploration cost	24	36	13	34	107
Capitalized interest	194	201	184	445	1,024
Total	$ 327	$ 336	$ 704	$ 3,435	$ 4,802

We also review, on a quarterly basis, the carrying value of our oil and natural gas properties under the full cost accounting rules of the Securities and Exchange Commission (SEC). This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for oil and natural gas derivatives designated as cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. The ceiling test calculation uses costs as of the end of the applicable quarterly period and the unweighted arithmetic average of oil, natural gas and NGL prices on the first day of each month within the 12-month period prior to the ending date of the quarterly period. These prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives designated as cash flow hedges. As of December 31, 2016, none of our open derivative instruments were designated as cash flow hedges. Our oil and natural gas hedging activities are discussed in Note 11.

Two primary factors impacting the ceiling test are reserves levels and oil, natural gas and NGL prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of oil and natural gas reserves and/or an increase or decrease in prices can have a material impact on the present value of our estimated future net revenues. Any excess of the net book value over the ceiling is written off as an expense.

We account for seismic costs as part of our oil and natural gas properties. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Further, exploration costs include, among other things, geological and geophysical studies and salaries and other expenses of geologists, geophysical crews and others conducting those studies. These costs are capitalized as incurred. The Company reviews its unproved properties and associated seismic costs quarterly to determine whether impairment has occurred. To the extent that seismic costs cannot be directly associated with specific unproved properties, they are included in the amortization base as incurred.

Other Property and Equipment

Other property and equipment consists primarily of natural gas compressors, buildings and improvements, land, vehicles, computers and office equipment. We have no remaining oilfield services equipment as a result of the spin-off of our oilfield services business in 2014, as discussed in Note 13. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operating expenses. See Note 16 for further discussion of our gains and losses on the sales of other property and equipment for the years ended 2016, 2015 and 2014 and a summary of our other property and equipment held for sale as of December 31, 2016 and 2015. Other property and equipment costs, excluding land, are depreciated on a straight-line basis.

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. During 2016, 2015 and 2014, we determined that certain of our property and equipment was being carried at values that were not recoverable and in excess of fair value. See Note 17 for further discussion of these impairments.

Capitalized Interest

Interest from external borrowings is capitalized on significant investments in unproved properties and 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, 2016 and 2015 are liabilities of approximately $77 million and $60 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 our revolving credit facility. The remaining unamortized issuance costs as of December 31, 2016 and 2015, totaled $32 million and $31 million, respectively, and are being amortized over the life of credit facility using the effective interest method. Included in debt are costs associated with the issuance of our senior notes. The remaining unamortized issuance costs as of December 31, 2016 and 2015, totaled $64 million and $43 million, respectively, and are being amortized over the life of the senior notes using the effective interest method.

Environmental Remediation Costs

Chesapeake records 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 20 for further discussion of asset retirement obligations.

Revenue Recognition

Oil, Natural Gas and NGL Sales. Revenue from the sale of oil, natural gas and NGL is recognized when title passes, net of royalties due to third parties.

Natural Gas Imbalances. We follow the sales method of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining estimated natural gas reserves on the underlying properties. The natural gas imbalance net liability position as of December 31, 2016 and 2015, was $9 million and $10 million, respectively.

Marketing, Gathering and Compression Sales. Chesapeake takes title to the oil, natural gas and NGL it purchases from other interest owners at defined delivery points and delivers the product to third parties, at which time revenues are recorded. In addition, we periodically enter into a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including credit risk mitigation and to help meet certain of our pipeline delivery commitments. In circumstances where we act as a principal rather than an agent, Chesapeake's results of operations related to its oil, natural gas and NGL marketing activities are presented on a gross basis. Gathering and compression revenues consist of fees billed to other interest owners in operated wells or third-party producers for the gathering, treating and compression of natural gas. Revenues are recognized when the service is performed and are based upon non-regulated rates and the related gathering, treating and compression volumes. All significant intercompany accounts and transactions have been eliminated.

Oilfield Services Revenue. Prior to the spin-off of our oilfield services business in June 2014, we reported oilfield services revenue. Our former oilfield services operating segment was responsible for contract drilling, hydraulic fracturing, rentals, trucking and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties. Revenues were recognized upon completion stages for our contract drilling, hydraulic fracturing and other oilfield services. Revenue was recognized ratably over the term of the rental for our oilfield rental services. Oilfield trucking services revenue was recognized as services were performed.

Fair Value Measurements

Certain financial instruments are reported at fair value on our consolidated balance sheets. 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 on our consolidated balance sheets as derivative assets or derivative liabilities at fair value, and changes in a derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are followed. For qualifying commodity derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. Locked-in gains and losses of settled cash flow hedges are recorded in accumulated other comprehensive income and are transferred to earnings in the month of production. Changes in the fair value of interest rate derivative instruments designated as fair value hedges are recorded on the consolidated balance sheets as assets or liabilities, and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent hedge ineffectiveness and are recognized currently in earnings. Locked-in gains and losses related to settled fair value hedges are amortized as an adjustment to interest expense over the remaining term of the related debt instrument. We have elected not to designate any of our qualifying commodity and interest rate derivatives as cash flow or fair value hedges. Therefore, changes in fair value of these derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are recognized in our consolidated statements of operations within oil, natural gas and NGL sales and interest expense, respectively.

From time to time and in the normal course of business, our marketing subsidiary enters into supply contracts under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas, thereby creating an embedded derivative requiring bifurcation. The changes in fair value of the embedded derivative and the settlements are recognized in our consolidated statements of operations within marketing, gathering and compression sales.

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 (i.e., commodity, interest rate and cross currency contracts) 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 11 for further discussion of our derivative instruments.

Share-Based Compensation

Chesapeake's share-based compensation program consists of restricted stock, stock options and performance share units granted to employees and restricted stock granted to non-employee directors under our Long Term Incentive Plan. We recognize in our financial statements 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 or four 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 can only be 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 exploration 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 expenses, oil, natural gas and NGL production expenses, or marketing, gathering and compression expenses, based on the employees involved in those activities. See Note 9 for further discussion of share-based compensation.

Reclassifications and Revisions

In April 2015, the Financial Accounting Standards Board (FASB) issued guidance that requires debt issuance costs related to term debt to be presented in the balance sheet as a direct reduction from the associated debt liability. This standard requires retrospective application and is effective for annual reporting periods beginning after December 15, 2015. This change in accounting principle is preferable since it allows both debt issuance costs and debt discounts to be presented similarly in the consolidated balance sheets as a direct reduction from the face amount of our debt balances. A retrospective change to our consolidated balance sheet as of December 31, 2015, as previously presented, is required pursuant to the guidance. The retrospective adjustment to the December 31, 2015 consolidated balance sheet is shown below.

	As Previously Reported	December 31, 2015 Adjustment Effect	As Adjusted
		($ in millions)	
Other long-term assets	$ 333	$ (43)	$ 290
Long-term debt, net	$ 10,354	$ (43)	$ 10,311

In addition, certain revisions have been made to the fair value of debt table included in Note 3 to conform to the presentation used for our 2016 disclosure. The 8.00% Senior Secured Second Lien Notes due 2022 were previously classified as Level 1 and should have been classified as Level 2, as these senior notes are not exchange-traded. The following table reflects the revisions made.

	As Previously Reported		December 31, 2015 Adjustment Effect		As Revised	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
			($ in millions)			
Short-term debt (Level 1)	$ 381	$ 366	$ —	$ —	$ 381	$ 366
Long-term debt (Level 1)[(a)]	$ 10,347	$ 3,735	$ (3,627)	$ (1,189)	$ 6,720	$ 2,546
Long-term debt (Level 2)	$ —	$ —	$ 3,584	$ 1,189	$ 3,584	$ 1,189

(a) The difference in the carrying amount is due to the debt issuance costs retrospective change noted above.

2. Earnings Per Share

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

Diluted EPS is calculated assuming the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For the years ended December 31, 2016, 2015 and 2014, our contingent convertible senior notes did not have a dilutive effect and therefore were excluded from the calculation of diluted EPS. See Note 3 for further discussion of our convertible notes and contingent convertible senior notes.

For the years ended December 31, 2016, 2015 and 2014, shares of common stock for the following dilutive securities were excluded from the calculation of diluted EPS as the effect was antidilutive.

	Shares (in millions)
Year Ended December 31, 2016	
Common stock equivalent of our preferred stock outstanding:	
5.75% cumulative convertible preferred stock	34
5.75% cumulative convertible preferred stock (series A)	18
5.00% cumulative convertible preferred stock (series 2005B)	5
4.50% cumulative convertible preferred stock	6
Participating securities	1
Common stock equivalent of our convertible senior notes outstanding:	
5.5% convertible senior notes	146
Common stock equivalent of our preferred stock outstanding prior to exchange:	
5.75% cumulative convertible preferred stock exchanged	19
5.75% cumulative convertible preferred stock (series A) exchanged	18
5.00% cumulative convertible preferred stock (series 2005B) exchanged	—
Year Ended December 31, 2015	
Common stock equivalent of our preferred stock outstanding:	
5.75% cumulative convertible preferred stock	59
5.75% cumulative convertible preferred stock (series A)	42
5.00% cumulative convertible preferred stock (series 2005B)	6
4.50% cumulative convertible preferred stock	6
Participating securities	1
Year Ended December 31, 2014	
Participating securities	3

For the year ended December 31, 2014, all outstanding equity securities convertible into common stock were included in the calculation of diluted EPS. A reconciliation of basic EPS and diluted EPS for the year ended December 31, 2014 is as follows:

	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Year Ended December 31, 2014:			
Basic EPS	$ 1,273	659	$ 1.93
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	86	59	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	63	42	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	10	6	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	12	6	
Diluted EPS	$ 1,444	772	$ 1.87

3. Debt

Our long-term debt consisted of the following as of December 31, 2016 and 2015:

	December 31, 2016		December 31, 2015	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
Term loan due 2021	$ 1,500	$ 1,500	$ —	$ —
3.25% senior notes due 2016	—	—	381	381
6.25% euro-denominated senior notes due 2017[(a)]	258	258	329	329
6.5% senior notes due 2017	134	134	453	453
7.25% senior notes due 2018	64	64	538	538
Floating rate senior notes due 2019	380	380	1,104	1,104
6.625% senior notes due 2020	780	780	822	822
6.875% senior notes due 2020	279	279	304	304
6.125% senior notes due 2021	550	550	589	589
5.375% senior notes due 2021	270	270	286	286
4.875% senior notes due 2022	451	451	639	639
8.00% senior secured second lien notes due 2022[(b)]	2,419	3,409	2,425	3,584
5.75% senior notes due 2023	338	338	384	384
8.00% senior notes due 2025	1,000	1,000	—	—
5.5% convertible senior notes due 2026[(c)(e)]	1,250	811	—	—
2.75% contingent convertible senior notes due 2035[(d)]	2	2	2	2
2.5% contingent convertible senior notes due 2037[(d)(e)]	114	112	1,110	1,027
2.25% contingent convertible senior notes due 2038[(d)(e)]	200	180	340	290
Revolving credit facility	—	—	—	—
Debt issuance costs	—	(64)	—	(43)
Discount on senior notes	—	(16)	—	(4)
Interest rate derivatives[(f)]	—	3	—	7
Total debt, net	9,989	10,441	9,706	10,692
Less current maturities of long-term debt, net[(g)]	(506)	(503)	(381)	(381)
Total long-term debt, net	$ 9,483	$ 9,938	$ 9,325	$ 10,311

(a) The principal and carrying amounts shown are based on the exchange rate of \$1.0517 to €1.00 and \$1.0862 to €1.00 as of December 31, 2016 and 2015, respectively. See *Foreign Currency Derivatives* in Note 11 for information on our related foreign currency derivatives.

(b) The carrying amounts as of December 31, 2016 and 2015, include premium amounts of \$990 million and \$1.159 billion, respectively, associated with a troubled debt restructuring. The premium is being amortized based on an effective yield method.

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

Optional Conversion by Holders. At the holder's option, prior to maturity under certain circumstances, the notes are convertible into cash, our common stock, or a combination of cash and common stock, at our election. One triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter, beginning with the first quarter of 2017. Convertibility based on common stock price is measured quarterly. 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, 2016. Upon conversion of a convertible senior note, the holder will receive cash, common stock or a combination of cash and common stock, at our election, according to the conversion rate specified in the indenture.

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

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

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

Holders' Demand Repurchase Rights. The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date.

Optional Conversion by Holders. At the holder's option, prior to maturity under certain circumstances, the notes are convertible into cash and, if applicable, our common stock using a net share settlement process. One triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period within a fiscal quarter. Convertibility based on common stock price is measured quarterly. During the specified period in the fourth quarter of 2016, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes and, as a result, the holders do not have the option to convert their notes into cash or common stock in the first quarter of 2017 under this provision.

The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision during the years ended December 31, 2016, 2015 and 2014. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of the principal amount.

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

The holders' demand repurchase dates, the common stock price conversion threshold amounts (as adjusted to give effect to cash dividends on our common stock) and the ending date of the first six-month period in which contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Holders' Demand Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2020, 2025, 2030	$ 45.02	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 59.44	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 100.20	June 14, 2019

Optional Redemption by the Company. We may redeem the contingent convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. In addition, we may redeem our 2.75% Contingent Convertible Senior Notes due 2035 at any time.

(e) The carrying amounts as of December 31, 2016 and 2015 are reflected net of discounts of $461 million and $133 million, respectively, associated with the equity component of our convertible and contingent convertible senior notes. This amount is being amortized based on an effective yield method through the first demand repurchase date as applicable.

(f) See Interest Rate Derivatives in Note 11 for further discussion related to these instruments.

(g) As of December 31, 2016, current maturities of long-term debt, net includes our 6.25% Euro-denominated Senior Notes due 2017, 6.5% Senior Notes due 2017 and our 2.5% Contingent Convertible Senior Notes due 2037 (2037 Notes). As discussed in footnote (b) above, the holders of our 2037 Notes could exercise their individual demand repurchase rights on May 15, 2017, which would require us to repurchase all or a portion of the principal amount of the notes. As of December 31, 2016, there was $2 million associated with the equity component of the 2037 Notes.

Total principal amount of debt maturities, using the earliest demand repurchase date for contingent convertible senior notes, for the five years ended after December 31, 2016 and thereafter are as follows:

	Principal Amount of Debt Securities
	($ in millions)
2017	$ 506
2018	264
2019	380
2020	1,061
2021	2,320
2022 and thereafter	5,458
Total	$ 9,989

See Note 23 for discussion of debt that has been retired, repurchased and redeemed in 2017.

Term Loan Facility

In 2016, we entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion for net proceeds of approximately $1.476 billion. Our obligations under the new facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility, second lien notes and senior notes and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 7.50% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 6.50% per annum, subject to a 2.00% ABR floor, at our option. The loan was made at par without original discount. We used the net proceeds to finance tender offers for our unsecured notes. The term loan matures in August 2021 and voluntary prepayments are subject to a make-whole premium prior to the second anniversary of the closing of the term loan, a premium to par of 4.25% from the second anniversary until but excluding the third anniversary, a premium to par of 2.125% from the third anniversary until but excluding the fourth anniversary and at par beginning on the fourth anniversary. The term loan may be subject to mandatory prepayments and offers to purchase with net cash proceeds of certain issuances of debt, certain asset sales and other dispositions of collateral and upon a change of control.

The term loan contains covenants limiting our ability to incur additional indebtedness, incur liens, consummate mergers and similar fundamental changes, make restricted payments, sell collateral and use proceeds from such sales, make investments, repay certain subordinate, unsecured or junior lien indebtedness, and enter into transactions with affiliates.

Events of default under the term loan include, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to other indebtedness with an outstanding principal balance of $125 million or more; bankruptcy; judgments involving liability of $125 million or more that are not paid; and ERISA events. Many events of default are subject to customary notice and cure periods.

Senior Secured Second Lien Notes

In December 2015, we completed private offers to exchange newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible senior notes (Existing Notes). The Second Lien Notes are secured second lien obligations and are effectively junior to our current and future secured first lien indebtedness, including indebtedness incurred under our revolving credit facility and our term loan facility, to the extent of the value of the collateral securing such indebtedness, effectively senior to all of our existing and future unsecured indebtedness, including our outstanding senior notes, to the extent of the value of the collateral, and senior to any future subordinated indebtedness that we may incur. We have the option to redeem the Second Lien Notes, in whole or in part, at specified make-whole or redemption prices. Our Second Lien Notes are governed by an indenture containing covenants that may limit our ability and our subsidiaries' ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, consolidate, merge or transfer assets and dispose of certain collateral and use proceeds from dispositions of certain collateral. As a holding company, Chesapeake owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake's obligations under the Second Lien Notes are fully and unconditionally guaranteed, jointly and severally, by certain of our direct and indirect wholly owned subsidiaries.

Certain of the Existing Notes that were exchanged for the Second Lien Notes were accounted for as a troubled debt restructuring (TDR). For the exchanges classified as a TDR, if the future undiscounted cash flows of the newly issued debt are less than the net carrying value of the original debt, a gain is recorded for the difference and the carrying value of the newly issued debt is adjusted to the future undiscounted cash flow amount and no future interest expense is recorded. All future interest payments on the newly issued debt reduce the carrying value. Accordingly, we recognized a gain of $304 million in our 2015 consolidated statement of operations, and the remaining reduction in principal amount of Existing Notes ($990 million as of December 31, 2016) is included in the carrying value of our Second Lien Notes. As a result, our reported interest expense will be significantly less than the contractual interest payments throughout the term of the Second Lien Notes. For the remaining TDR exchanges, where the future undiscounted cash flows are greater than the net carrying value of the original debt, no gain is recognized and a new effective interest rate is established. For the other Existing Notes that were exchanged that did not qualify as a TDR, we accounted for these exchanges as either a modification or extinguishment. Direct costs incurred of $30 million in 2015 related to the notes exchange were expensed and are included within gains (losses) on purchases or exchanges of debt in our consolidated statement of operations.

Senior Notes, Contingent Convertible Senior Notes and Convertible Senior Notes

The senior notes and the convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake's obligations under the senior notes and the convertible senior notes are fully and unconditionally guaranteed, jointly and severally, by certain of our direct and indirect wholly owned subsidiaries.

Chesapeake Energy Corporation is a holding company and has no independent assets or operations. Our obligations under our outstanding senior notes and convertible senior notes are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries on a senior unsecured basis. Our non-guarantor subsidiaries are minor and, as such, we have not included condensed consolidating financial information in the notes to our consolidated financial statements.

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 Second Lien Notes, senior notes and convertible senior notes have cross default provisions that apply to other indebtedness the Company or any guarantor subsidiary may have from time to time with an outstanding principal amount of at least $50 million or $75 million, depending on the indenture.

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

During 2016, we issued in a private placement $1.0 billion principal amount of unsecured 8.00% Senior Notes due 2025 at a discount for net proceeds of approximately $975 million. Some or all of the notes may be redeemed at any time prior to January 15, 2020, subject to a make-whole premium. In addition, we may redeem some or all of the notes at any time on or after January 15, 2020, 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, Chesapeake may redeem up to 35% of the aggregate principal amount of the notes at any time prior to January 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 by Chesapeake.

During 2016, we issued in a private placement $1.25 billion principal amount of unsecured 5.5% Convertible Senior Notes due 2026 at par for net proceeds of approximately $1.235 billion. The notes are convertible, under certain specified circumstances, into cash, common stock, or a combination of cash and common stock, at our election. We accounted for the liability and equity components separately and reflected interest expense at the interest rate of similar nonconvertible debt at the time of issuance. The allocation to the equity component of the convertible notes was $445 million ($165 million tax expense). Additionally, debt issuance costs were allocated in proportion to the liability and equity components and accounted for as debt issuance costs and equity issuance costs, respectively. The accretion of the resulting discount on the debt is recognized through the convertible note's maturity date as a component of interest expense, thereby increasing the amount of interest expense required to be recognized with respect to such instruments.

During 2016, we used the net proceeds from our term loan and convertible and senior notes issuances discussed above, together with cash on hand, to purchase and retire $1.451 billion principal amount of our outstanding senior notes and $708 million principal amount of our outstanding contingent convertible senior notes for an aggregate $2.078 billion pursuant to tender offers.

During 2016, in addition to the repayment upon maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $325 million principal amount of our outstanding senior notes for $300 million and $141 million principal amount of our outstanding contingent convertible senior notes for $86 million.

Additionally, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of common stock.

For the year ended December 31, 2016, we recorded an aggregate net gain of approximately $236 million associated with the tender offers, debt repurchases and exchanges discussed above, which was net of $26 million ($10 million tax benefit) associated with the equity component of the retired contingent convertible senior notes.

During 2015, as required by the terms of the indenture for our 2.75% Contingent Convertible Senior Notes due 2035 (the 2035 Notes), the holders were provided the option to require us to purchase on November 15, 2015, all or a portion of the holders' 2035 Notes at par plus accrued and unpaid interest up to, but excluding, November 15, 2015. On November 16, 2015, we paid an aggregate of approximately $394 million to purchase all of the 2035 Notes that were tendered and not withdrawn. An aggregate of $2 million principal amount of the 2035 Notes remains outstanding as of December 31, 2016.

During 2015, we repurchased in the open market approximately $119 million aggregate principal amount of our 3.25% Senior Notes due 2016 for cash. We recorded a gain of approximately $5 million associated with the repurchase.

During 2014, we issued $3.0 billion in aggregate principal amount of senior notes at par. The offering included two series of notes: $1.5 billion in aggregate principal amount of Floating Rate Senior Notes due 2019 and $1.5 billion in aggregate principal amount of 4.875% Senior Notes due 2022. We used a portion of the net proceeds of $2.966 billion to repay the borrowings under, and terminate, our then-existing term loan credit facility. We used the remaining proceeds along with cash on hand to redeem the remaining $97 million principal amount of the 6.875% Senior Notes due 2018 and to purchase and redeem the remaining $1.265 billion principal amount of the 9.5% Senior Notes due 2015 for $1.454 billion. We recorded a loss of approximately $6 million associated with the redemption of the 6.875% Senior Notes due 2018, which consisted of $5 million in premiums and $1 million of unamortized deferred charges. We recorded a loss of approximately $99 million associated with the purchase and redemption of the 9.5% Senior Notes due 2015, which consisted of $87 million in premiums, $9 million of unamortized discount and $3 million of unamortized deferred charges.

Revolving Credit Facility

We have a $4.0 billion senior secured revolving credit facility (currently subject to a $3.8 billion borrowing base) that matures in December 2019. As of December 31, 2016, we had no outstanding borrowings under the revolving credit facility and had used $1.036 billion of the revolving credit facility for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation discussed in Note 4). The terms of the revolving credit facility include covenants limiting, among other things, our ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates. We were in compliance with all applicable financial covenants under the agreement as of December 31, 2016.

During 2016, we entered into the third amendment to our revolving credit facility. Pursuant to the amendment, our borrowing base was reaffirmed in the amount of $4.0 billion and the next scheduled borrowing base redetermination review was postponed until June 15, 2017, with the consenting lenders agreeing not to exercise their interim redetermination right prior to that date. Our borrowing base may be reduced if we dispose of a certain percentage of the value of collateral securing the facility. As a result of certain asset sales discussed in Note 12 and certain other sales of collateral since the date of the most recent amendment, our borrowing base was reduced to $3.8 billion as of December 31, 2016. The amendment also provides temporary financial covenant relief, with the revolving credit facility's existing first lien secured leverage ratio and net debt to capitalization ratio suspended until September 30, 2017 and the interest coverage ratio maintenance covenant reduced as noted below. In addition, we agreed to grant liens and security interests on a majority of our assets, as well as maintain a minimum liquidity amount (defined as cash and cash equivalents and availability under our revolving credit facility) of $500 million until the suspension of the existing maintenance covenants ends.

The amendment reduces the interest coverage ratio from 1.1 to 1.0 to 0.65 to 1.0 through the first quarter of 2017, after which it will increase to 0.70 to 1.0 for the second quarter of 2017, 1.2 to 1.0 for the third quarter of 2017 and 1.25 to 1.0 thereafter. The amendment also includes a collateral value coverage test whereby if the collateral value coverage ratio, tested as of December 31, 2016, falls below 1.1 to 1.0, the $500 million minimum liquidity covenant increases to $750 million, and if the collateral value coverage ratio, tested as of March 31, 2017, falls below 1.25 to 1.0, our borrowing ability will be reduced in order to satisfy such ratio. The amendment also gives us the ability to incur up to $2.5 billion of first lien indebtedness secured on a pari passu basis with the existing obligations under the credit agreement, subject to a position in the collateral proceeds waterfall in favor of the revolving lenders and affiliated hedge providers and the other limitations on junior lien debt set forth in the credit agreement. After taking into account the term loan, the amount of additional first lien indebtedness permitted by the revolving credit facility is $1.0 billion.

Fair Value of Debt

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

	December 31, 2016		December 31, 2015	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$ 503	$ 511	$ 381	$ 366
Long-term debt (Level 1)	$ 3,271	$ 3,216	$ 6,720	$ 2,546
Long-term debt (Level 2)	$ 6,664	$ 6,654	$ 3,584	$ 1,189

4. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.

2016 Shareholder Litigation. On April 19, 2016, a shareholder lawsuit was filed in the U.S. District Court for the Western District of Oklahoma against the Company and current and former directors and officers of the Company alleging, among other things, violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act, breach of fiduciary duties, waste of corporate assets, gross mismanagement and violations of Sections 10(b) and Rule 10b-5 of the Exchange Act related to actions allegedly taken by such persons since 2008. The lawsuit sought to assert derivative and direct claims, certification as a class action, damages, attorneys' fees and other costs. The District Court dismissed the plaintiffs' claims on August 30, 2016.

Regulatory and Related Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.

In addition, the Company received a DOJ subpoena and a voluntary document request from the SEC seeking information on our accounting methodology for the acquisition and classification of oil and natural gas properties and related matters. Chesapeake has engaged in discussions with the DOJ and SEC about these matters. On October 4, 2016, a securities class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and certain current directors and officers of the Company alleging, among other things, violations of federal securities laws for purported misstatements in the Company's SEC filings and other public disclosures regarding the Company's accounting for the acquisition and classification of oil and natural gas properties. The lawsuit seeks certification as a class action, damages, attorneys' fees and other costs.

Redemption of 2019 Notes. As previously disclosed in the 2015 Form 10-K, in connection with the litigation related to the Company's notice issued on March 15, 2013, to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes, the Company filed a notice of appeal on July 27, 2015, of an amended judgment entered on July 17, 2015, by the U.S. District Court for the Southern District of New York awarding the Trustee for the 2019 Notes $380 million plus prejudgment interest in the amount of $59 million. The Company posted a supersedeas bond in the amount of $461 million (reflected as an outstanding letter of credit under the Company's revolving credit facility) to stay execution of the judgment while appellate proceedings are pending. The Company accrued a loss contingency of $100 million for this matter in 2014 and an additional $339 million in 2015. On September 15, 2016, the United States Court of Appeals for the Second Circuit affirmed the trial court's ruling. On February 2, 2017, the Company filed a petition for writ of certiorari with the United States Supreme Court seeking review of the Court of Appeals' decision.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts and has settled and resolved other such cases and disputes.

Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. Plaintiffs have varying royalty provisions in their respective leases, oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. The Company has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages with respect to royalty underpayment in various states, including, but not limited to, Texas, Pennsylvania, Ohio, Oklahoma, Kentucky, Louisiana and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ, U.S. Postal Service and state subpoenas or information requests seeking information on the Company's royalty payment practices.

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

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

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company's divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources.

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

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

Other Matters

In April 2016, a class action lawsuit on behalf of holders of the Company's 6.875% Senior Notes due 2020 (the 2020 Notes) and 6.125% Senior Notes due 2021 (2021 Notes) was filed in the U.S. District Court for the Southern District of New York relating to the Company's December 2015 debt exchange, whereby the Company privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible notes. The lawsuit alleges that the Company violated the Trust Indenture Act of 1939 and the implied covenant of good faith and fair dealing by benefiting themselves and a minority of noteholders who are qualified institutional buyers (QIBs). According to the lawsuit, as a result of the Company's private debt exchange in which only QIBs (and non-U.S. persons under Regulation S) were eligible to participate, the Company unjustly enriched itself at the expense of class members by reducing indebtedness and reducing the value of the 2020 Notes and the 2022 Notes. The lawsuit seeks damages and attorney's fees, in addition to declaratory relief that the debt exchange and the liens created for the benefit of the Second Lien Notes are null and void and that the debt exchange effectively resulted in a default under the indentures for the 2020 Notes and the 2021 Notes. In June 2016, the lawsuit was transferred to the United States District Court for the Western District of Oklahoma, and in October 2016, the Company filed a motion to dismiss for failure to state a claim. The District Court dismissed the plaintiffs' claims on February 8, 2017.

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

Environmental Contingencies

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

Commitments

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, 2016
	($ in millions)
2017	$ 4
2018	3
2019	2
Total	$ 9

Lease expense for the years ended December 31, 2016, 2015 and 2014, was $5 million, $7 million and $33 million, respectively. Lease expense decreased significantly in 2016 and 2015 compared to 2014 primarily due to the repurchase of all rigs and compressors previously sold under long-term sale-leaseback arrangements.

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 proportionate share of these costs 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, 2016
	($ in millions)
2017	$ 1,434
2018	1,229
2019	1,178
2020	1,074
2021	970
2022 – 2099	5,225
Total	$ 11,110

In addition to the above commitments, we have entered into long-term agreements for certain natural gas gathering and related services within specified acreage dedication areas in exchange for cost-of-service based fees redetermined annually, or tiered fees based on volumes delivered relative to scheduled volumes. Future gathering fees vary with the applicable agreement.

Drilling Contracts

We have contracts with various drilling contractors to utilize drilling services at market-based pricing. These commitments are not recorded as obligations in the accompanying consolidated balance sheets. As of December 31, 2016, the aggregate undiscounted minimum future payments under these drilling service commitments are detailed below.

	December 31, 2016
	($ in millions)
2017	$ 91
2018	14
Total	$ 105

Pressure Pumping Contracts

We have an agreement for pressure pumping services, which expires in June 2017. The services agreement requires us to utilize, at market-based pricing, the lesser of (i) three pressure pumping crews through June 30, 2017, or (ii) 50% of the total number of all pressure pumping crews working for us in all of our operating regions during the respective year. We are also required to utilize the pressure pumping services for a minimum number of fracture stages as set forth in the agreement. We are entitled to terminate the agreement in certain situations, including if the contractor fails to provide the overall quality of service provided by similar service providers. These commitments are not recorded as obligations in the accompanying consolidated balance sheets. As of December 31, 2016, the aggregate undiscounted minimum future payments under this agreement were approximately $53 million.

Oil, Natural Gas and NGL Purchase Commitments

We commit to purchase oil, natural gas and NGL from other owners in the properties we operate, including owners associated with our volumetric production payment (VPP) transactions. Production purchases under these arrangements are based on market prices at the time of production, and the purchased oil, natural gas and NGL are resold at market prices. See *Volumetric Production Payments* in Note 12 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

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

Other Commitments

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

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

Certain of our oil and natural gas properties are burdened by non-operating interests such as royalty and overriding royalty interests, including overriding royalty interests sold through our VPP transactions. As the holder of the working interest from which these interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to these interests. See *Volumetric Production Payments* in Note 12 for further discussion of our VPP transactions.

While executing our strategic priorities, we have incurred certain cash charges, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. As we continue to focus on our strategic priorities, we may take certain actions that reduce financial leverage and complexity, and we may incur additional cash and noncash charges.

5. Other Liabilities

Other current liabilities as of December 31, 2016 and 2015 are detailed below.

	December 31, 2016	December 31, 2015
	($ in millions)	
Revenues and royalties due others	$ 543	$ 500
Accrued drilling and production costs	169	212
Joint interest prepayments received	71	169
Accrued compensation and benefits	239	264
Other accrued taxes	32	37
Bank of New York Mellon legal accrual	440	439
Minimum gathering volume commitment	—	201
Other	304	397
Total other current liabilities	$ 1,798	$ 2,219

Other long-term liabilities as of December 31, 2016 and 2015 are detailed below.

	December 31, 2016	December 31, 2015
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$ 160	$ 190
Financing obligations	—	29
Unrecognized tax benefits	97	64
Other	126	126
Total other long-term liabilities	$ 383	$ 409

(a) Approximately $43 million and $21 million of the total $203 million and $211 million obligations are recorded in other current liabilities as of December 31, 2016 and 2015, respectively. See *Noncontrolling Interests* in Note 8 for further discussion of the transaction.

6. Income Taxes

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

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Current			
Federal	$ (14)	$ —	$ —
State	(5)	(36)	47
Current Income Taxes	(19)	(36)	47
Deferred			
Federal	(147)	(4,385)	1,115
State	(24)	(42)	(18)
Deferred Income Taxes	(171)	(4,427)	1,097
Total	$ (190)	$ (4,463)	$ 1,144

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,		
	2016	2015	2014
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (35%)	$ (1,606)	$ (6,684)	$ 1,120
State income taxes (net of federal income tax benefit)	(30)	(406)	68
Remeasurement of state deferred tax liabilities	—	—	(114)
Change in valuation allowance	1,423	2,727	74
Other	23	(100)	(4)
Total	$ (190)	$ (4,463)	$ 1,144

In accordance with U.S. GAAP, intraperiod tax allocation provisions require allocation of $190 million of tax benefit to continuing operations. This tax benefit was partially offset by $165 million of tax expense and $10 million of tax benefit associated with the equity components of the debt transactions that occurred during the year. See Note 3 for further discussion of our debt transactions. Additionally, $4 million of tax expense was allocated to other comprehensive income. The result is a net tax benefit of $31 million which is primarily due to tax elections that allow for realization of deferred tax assets related to alternative minimum tax (AMT) credits.

We reassessed the realizability of our deferred tax assets given the low commodity prices and recorded a $1.423 billion increase in our valuation allowance in our consolidated statement of operations for the year ended December 31, 2016. The increase in the valuation allowance is to offset the portion of the tax benefit at expected rates that we believe is more likely than not to not be realized.

Deferred income taxes are provided to reflect temporary differences in the basis of net assets for income tax and financial reporting purposes. The tax-effected temporary differences and tax loss carryforwards which comprise deferred taxes are as follows:

	Years Ended December 31,	
	2016	2015
	($ in millions)	
Deferred tax liabilities:		
Volumetric production payments	$ (223)	$ (802)
Derivative instruments	—	(300)
Other	(62)	(71)
Deferred tax liabilities	(285)	(1,173)
Deferred tax assets:		
Property, plant and equipment	593	1,144
Net operating loss carryforwards	2,587	1,556
Carrying value of debt	539	532
Asset retirement obligations	98	174
Investments	275	260
Derivative instruments	161	—
Accrued liabilities	319	333
Other	118	123
Deferred tax assets	4,690	4,122
Valuation allowance	(4,389)	(2,949)
Net deferred tax assets	301	1,173
Net deferred tax assets[(a)]	$ 16	$ —

(a) The net deferred tax assets are included in other long-term assets in the accompanying balance sheets.

As of December 31, 2016, Chesapeake had federal income tax NOL carryforwards of approximately $6.2 billion and state NOL carryforwards of approximately $9.5 billion which excludes the NOL carryforwards related to unrecognized tax benefits. The associated deferred tax assets related to these NOL carryforwards were $2.161 billion and $426 million, respectively. The NOL carryforwards expire between 2031 and 2036. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. As of December 31, 2016 and 2015, we had deferred tax assets of $4.690 billion and $4.122 billion upon which we had a valuation allowance of $4.389 billion and $2.949 billion, respectively. Of the net change in the valuation allowance of $1.440 billion for both federal and state deferred tax assets, $1.423 billion is reflected as a component of income tax expense in the consolidated statement of operations and $17 million is reflected as a component of equity.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry. As of December 31, 2016, we believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the cumulative loss incurred over the three-year period ending December 31, 2016. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of these carryforwards 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 defined in the 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, 2016, we do not believe that an ownership change has occurred that would limit our NOL carryforwards. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. As of December 31, 2016 and 2015, the amount of unrecognized tax benefits related to NOL carryforwards and state tax liabilities associated with uncertain tax positions was $202 million and $280 million, respectively. Of the 2016 amount, $76 million is related to state tax liabilities while the remainder is related to NOL carryforwards. Of the 2015 amount, $44 million is related to state tax liabilities while the remainder is related to NOL carryforwards. The uncertain tax positions identified would not have a material effect on the effective tax rate. No material changes to the current uncertain tax positions are expected within the next 12 months. As of both December 31, 2016 and 2015, we had accrued liabilities of $20 million for interest related to these uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in 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:

	2016	2015	2014
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 280	$ 303	$ 644
Additions based on tax positions related to the current year	—	27	13
Additions to tax positions of prior years	33	—	—
Settlements	(111)	—	—
Reductions to tax positions of prior years	—	(50)	(354)
Unrecognized tax benefits at end of period	$ 202	$ 280	$ 303

Chesapeake's federal and state income tax returns are routinely audited by federal and state fiscal authorities. The Internal Revenue Service (IRS) is currently auditing our federal income tax returns for 2010 through 2015. The 2010 through 2016 years and the 2007 through 2016 years remain open for all purposes of examination by the IRS and other taxing authorities in material jurisdictions, respectively.

7. 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 FTS International, Inc. (FTS). 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, 2016, 2015 and 2014, our expenditures for hydraulic fracturing services with FTS were $3 million, $65 million and $220 million, respectively.

8. Equity

Common Stock

A summary of the changes in our common shares issued for the years ended December 31, 2016, 2015 and 2014 is detailed below.

	Years Ended December 31,		
	2016	2015	2014
	(in thousands)		
Shares issued as of January 1	664,796	664,944	666,192
Exchange of convertible notes	55,428	—	—
Exchange of senior notes	53,924	—	—
Conversion of preferred stock	120,186	—	—
Restricted stock issuances (net of forfeitures and cancellations)[a]	1,945	(163)	(2,529)
Stock option exercises	—	15	1,281
Shares issued as of December 31	896,279	664,796	664,944

(a) The amount for 2014 reflects forfeitures upon the June 2014 spin-off of our oilfield services business.

During the year ended December 31, 2016, our shareholders approved an amendment to our certificate of incorporation to increase our authorized common stock from 1,000,000,000 shares to 1,500,000,000 shares, par value $0.01 per share.

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2016:

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	$ 32.7572
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, 2016, 2015 and 2014 are detailed below.

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
		(in thousands)		
Shares outstanding as of January 1, 2016	1,497	1,100	2,559	2,096
Preferred stock conversions/exchanges[(a)]	(654)	(624)	—	(134)
Shares outstanding as of December 31, 2016	843	476	2,559	1,962
Shares outstanding as of January 1, 2015 and December 31, 2015	1,497	1,100	2,559	2,096
Shares outstanding as of January 1, 2014 and December 31, 2014	1,497	1,100	2,559	2,096

(a) During 2016, holders of our 5.75% Cumulative Convertible Preferred Stock exchanged or converted 653,872 shares into 59,141,429 shares of common stock, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock exchanged or 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

In January 2016, we announced that we were suspending dividend payments on each series of our outstanding convertible preferred stock. Suspension of the dividends did not constitute an event of default under our revolving credit facility or bond indentures. Our preferred stock dividends for the year ended December 31, 2016 (paid in arrears) are detailed below.

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
		($ in millions)		
Dividends in arrears	$ 48	$ 27	$ 12	$ 10

On February 15, 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, 2016 and 2015, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below.

	Years Ended December 31, 2016	Years Ended December 31, 2015
	($ in millions)	
Balance, beginning of period	$ (99)	$ (143)
Other comprehensive income before reclassifications	(13)	20
Amounts reclassified from accumulated other comprehensive income	16	24
Net other comprehensive income (loss)	3	44
Balance, end of period	$ (96)	$ (99)

For the years ended December 31, 2016 and 2015, amounts reclassified from accumulated other comprehensive income (loss), net of tax, into the consolidated statements of operations are detailed below.

Details About Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income is Presented	Amounts Reclassified
		($ in millions)
Year Ended December 31, 2016		
Net losses on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$ 16
Foreign currency derivative	Gain (loss) on purchases or exchanges of debt	—
Total reclassifications for the period, net of tax		$ 16
Year Ended December 31, 2015		
Net losses on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$ 23
Foreign currency derivative	Gain (loss) on purchases or exchanges of debt	1
Total reclassifications for the period, net of tax		$ 24

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK C-T in March 2012 to continue development of a portion of our oil and natural gas assets in our Cleveland and Tonkawa plays. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 future net wells to be drilled on the contributed play leasehold. We initially committed to drill and complete, for the benefit of CHK C-T in the area of mutual interest, a minimum cumulative total of 300 net wells. We ultimately drilled and completed 190 net wells, and the drilling commitment was suspended in January 2015.

During 2015, CHK C-T sold all of its oil and natural gas properties to FourPoint Energy, LLC and immediately used the consideration received, plus other cash it had on hand, to repurchase and cancel all of the outstanding preferred shares in CHK C-T. In connection with the repurchase and cancellation of the CHK C-T preferred stock and related agreements with the CHK C-T investors, we eliminated quarterly preferred dividend payments and all related future drilling and ORRI commitments attributable to CHK C-T. The sale of the oil and natural gas properties was accounted for as a reduction of capitalized costs with no gain or loss recognized.

For 2015 and 2014, income of $50 million and $75 million, respectively, was attributable to the noncontrolling interests of CHK C-T.

Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale oil and natural gas assets. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% ORRI in 1,500 net wells to be drilled on certain of our Utica Shale leasehold.

In July 2014, we repurchased all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders for approximately $1.254 billion, or approximately $1,189 per share including accrued dividends. The $447 million difference between the cash paid for the preferred shares and the carrying value of the noncontrolling interest acquired was reflected in retained earnings and as a reduction to net income available to common stockholders for purposes of our EPS computations. Pursuant to the transaction, our obligation to pay quarterly dividends to third-party preferred shareholders was eliminated. In addition, the development agreement was terminated pursuant to the transaction, which eliminated our obligation to drill and complete a minimum number of wells within a specified period for the benefit of CHK Utica. Our repurchase of the outstanding preferred shares in CHK Utica did not affect our obligation to deliver a 3% ORRI in 1,500 net wells on certain of our Utica Shale leasehold.

The CHK Utica investors' right to receive, proportionately, a 3% ORRI in the first 1,500 net wells drilled on certain of our Utica Shale leasehold is subject to an increase to 4% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs through 2023. However, in no event are we required to deliver to investors more than a total ORRI of 3% in 1,500 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 150-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of the remaining ORRIs. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of the remaining ORRIs once we have drilled a minimum of 1,300 net wells. As of December 31, 2016, we had drilled 508 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our oil and natural gas properties. We met our ORRI conveyance commitments as of December 31, 2014 and 2015 but did not meet our commitment in 2016. The ORRI will increase to 4% for wells drilled in 2017.

In 2014, income of approximately $43 million was attributable to the noncontrolling interests of CHK Utica.

Chesapeake Granite Wash Trust. In November 2011, Chesapeake Granite Wash Trust (the Trust) sold 23,000,000 common units representing beneficial interests in the Trust at a price of $19.00 per common unit in its initial public offering. The common units are listed on the New York Stock Exchange and trade under the symbol "CHKR". We own 12,062,500 common units and 11,687,500 subordinated units, which in the aggregate represent an approximate 51% beneficial interest in the Trust. The Trust has a total of 46,750,000 units outstanding.

The subordinated units we hold in the Trust are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is not less than the applicable subordination threshold for the quarter. If there is not sufficient cash to fund a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units is reduced or eliminated for the quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. The distribution made with respect to the subordinated units to Chesapeake was either reduced or eliminated for each of the most recent 18 quarters. In exchange for agreeing to subordinate a portion of our Trust units, and in order to provide additional financial incentive to us to perform operations on the underlying properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on the Trust units in any quarter exceeds the applicable incentive threshold for the quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold is to be paid to Trust unitholders, including Chesapeake, on a pro rata basis. Through December 31, 2016, no incentive distributions had been made. At the end of the 2017 second quarter, the subordinated units will automatically convert into common units on a one-for-one basis and our right to receive incentive distributions will terminate. After this time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share in the Trust's distributions on a pro rata basis.

For the years ended December 31, 2016, 2015 and 2014, the Trust declared and paid the following distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
June 2016 – August 2016	December 1, 2016	$ 0.0857	$ —
March 2016 – May 2016	August 29, 2016	$ 0.0734	$ —
December 2015 – February 2016	May 31, 2016	$ 0.0403	$ —
September 2015 – November 2015	March 1, 2016	$ 0.2195	$ —
June 2015 – August 2015	November 30, 2015	$ 0.3232	$ —
March 2015 – May 2015	August 31, 2015	$ 0.3579	$ —
December 2014 – February 2015	June 1, 2015	$ 0.3899	$ —
September 2014 – November 2014	March 2, 2015	$ 0.4496	$ —
June 2014 – August 2014	December 1, 2014	$ 0.5079	$ —
March 2014 – May 2014	August 29, 2014	$ 0.5796	$ —
December 2013 – February 2014	May 30, 2014	$ 0.6454	$ —
September 2013 – November 2013	March 3, 2014	$ 0.6624	$ —

We have determined that the Trust is a variable interest entity (VIE) and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our consolidated financial statements. As of December 31, 2016 and 2015, we had $257 million and $259 million, respectively, of noncontrolling interests on our consolidated balance sheets attributable to the Trust. Net income attributable to the Trust's noncontrolling interest is presented in our consolidated statements of operations as $2 million for the year ended December 31, 2016, a nominal amount for the year ended December 2015 and $24 million for the year ended December 31, 2014. See Note 15 for further discussion of VIEs.

9. Share-Based Compensation

Chesapeake's share-based compensation program consists of restricted stock, stock options and performance share units (PSUs) granted to employees and restricted stock granted to non-employee directors under our long term incentive plans. The restricted stock and stock options are equity-classified awards and the PSUs are liability-classified awards. In connection with the spin-off of our oilfield services business on June 30, 2014, and pursuant to the terms of our share-based compensation plans and the employee matters agreement between Chesapeake and Seventy Seven Energy Inc. (SSE), unexercised stock options and unvested restricted stock were modified as of the date of the spin-off. The modifications were designed to ensure that the value of each award of unexercised stock options and unvested restricted stock did not change as a result of the spin-off. The number of stock options and number of shares of restricted stock reported below have been adjusted to reflect modifications on the spin-off date.

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 withhold 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, 2016, 61,856,065 shares of common stock remained issuable under the 2014 LTIP.

Equity-Classified Awards

Restricted Stock. We grant restricted stock units to employees and non-employee directors. Prior to 2014, we also granted restricted stock awards as equity compensation. We refer to both types of awards as restricted stock. A summary of the changes in unvested restricted stock during 2016, 2015 and 2014 is presented below.

	Shares of Unvested Restricted Stock		Weighted Average Grant Date Fair Value
	(in thousands)		
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
Unvested restricted stock as of January 1, 2015	10,091	$	21.20
Granted	7,095	$	13.90
Vested	(4,157)	$	21.70
Forfeited	(2,574)	$	16.98
Unvested restricted stock as of December 31, 2015	10,455	$	17.31
Unvested restricted stock as of January 1, 2014	13,400	$	23.38
Granted	5,049	$	25.92
Vested	(4,803)	$	27.17
Forfeited	(3,555)	$	28.09
Unvested restricted stock as of December 31, 2014	10,091	$	21.20

The aggregate intrinsic value of restricted stock that vested during 2016 was approximately $21 million based on the stock price at the time of vesting.

As of December 31, 2016, there was approximately $50 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 1.5 years.

Stock Options. In 2016, 2015 and 2014, we granted members of senior management stock options that vest ratably over a three-year period. Each stock option award has an exercise price equal to the closing price of the Company's common stock on the grant date. Outstanding options expire seven to ten years from the date of grant.

We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The expected life of an option is determined using the simplified method. Volatility assumptions are estimated based on an average of historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account the Company's dividend policy, over the expected life of the option. The Company used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in 2016.

Expected option life – years	6.0
Volatility	46.07%
Risk-free interest rate	1.70%
Dividend yield	—%

The following table provides information related to stock option activity for 2016, 2015 and 2014.

	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, 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	$ —
Outstanding as of January 1, 2015	4,599	$ 19.55	7.03	$ 5
Granted	1,208	$ 18.37		
Exercised	(14)	$ 18.13		$ —
Expired	(416)	$ 18.46		
Forfeited	—	$ —		
Outstanding as of December 31, 2015	5,377	$ 19.37	5.80	$ —
Exercisable as of December 31, 2015	2,045	$ 19.61	5.07	$ —
Outstanding as of January 1, 2014	5,268	$ 19.28	6.66	$ 41
Granted	994	$ 24.43		
Exercised	(1,322)	$ 18.71		$ 11
Expired	(28)	$ 18.97		
Forfeited	(313)	$ 21.05		
Outstanding as of December 31, 2014	4,599	$ 19.55	7.03	$ 5
Exercisable as of December 31, 2014	1,304	$ 18.71	5.70	$ 1

(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, 2016, there was $7 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 1.70 years.

Restricted Stock and Stock Option Compensation. We recognized the following compensation costs related to restricted stock and stock options for the years ended December 31, 2016, 2015 and 2014.

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
General and administrative expenses	$ 38	$ 43	$ 46
Oil and natural gas properties	16	23	29
Oil, natural gas and NGL production expenses	13	18	18
Marketing, gathering and compression expenses	1	5	6
Oilfield services expenses	—	—	5
Total	$ 68	$ 89	$ 104

Liability-Classified Awards

Performance Share Units. We have granted PSUs to senior management that vest ratably over a three-year term and are settled in cash on the third anniversary of the awards. The ultimate amount earned is based on achievement of performance metrics established by the Compensation Committee of the Board of Directors, which include total shareholder return (TSR) and, for certain of the awards, operational performance goals such as finding and development costs and production levels.

For PSUs granted in 2016, the TSR component can range from 0% to 100% and the operational component can range from 0% to 100%, resulting in a maximum payout of 200%. For PSUs granted in 2015, the TSR component can range from 0% to 100%, and each of the two operational components can range from 0% to 50% resulting in a maximum total payout of 200%. For PSUs granted in 2014, the TSR component can range from 0% to 200%, with no operational components. Compensation expense associated with PSU grants is recognized over the service period based on the graded-vesting method. The value of the PSU awards at the end of each reporting period is dependent upon the Company’s estimates of the underlying performance measures. The Company utilized a Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs. The payout percentage for all PSU grants is capped at 100% if the Company's absolute TSR is less than zero.

Volatility	91.19%
Risk-free interest rate	1.20%
Dividend yield for value of awards	—%

The following table presents a summary of our 2016, 2015 and 2014 PSU awards.

			December 31, 2016	
	Units	Grant Date Fair Value	Fair Value	Vested Liability
		($ in millions)		
2016 Awards:				
Payable 2019	2,348,893	$ 10	$ 20	$ 12
2015 Awards:				
Payable 2018	629,694	$ 13	$ 4	$ 3
2014 Awards:				
Payable 2017	561,215	$ 16	$ —	$ —

PSU Compensation. We recognized the following compensation costs (credits) related to PSUs for the years ended December 31, 2016, 2015 and 2016.

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
General and administrative expenses	$ 14	$ (19)	$ (4)
Restructuring and other termination costs	1	(19)	(19)
Marketing, gathering and compression	—	(1)	—
Oil and natural gas properties	—	(2)	3
Total	$ 15	$ (41)	$ (20)

Effect of the Spin-off on Share-Based Compensation

The employee matters agreement entered into in connection with the June 2014 spin-off of our oilfield services business (see Note 13) addresses the treatment of holders of Chesapeake stock options, restricted stock and PSUs that were impacted by the spin-off. Unvested equity-based compensation awards held by Chesapeake Oilfield Operating, L.L.C. (COO) employees were canceled and replaced with new awards of SSE, and unvested equity-based compensation awards held by Chesapeake employees were adjusted to account for the spin-off, each as of the spin-off date. The employee matters agreement provides that employees of SSE ceased to participate in benefit plans sponsored or maintained by Chesapeake as of the spin-off date. In addition, the employee matters agreement provides that as of the spin-off date, each party is responsible for the compensation of its current employees and for all liabilities relating to its former employees, as determined by their respective employer on the date of termination.

10. 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. Through December 31, 2014, Chesapeake matched employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's base salary and performance bonus) with Chesapeake common stock purchased in the open market. Beginning January 1, 2015, Chesapeake matched employee contributions in cash. The Company contributed $39 million, $52 million and $61 million to the 401(k) Plan in 2016, 2015 and 2014, respectively.

Chesapeake also maintains 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. Only the top 10% of Company wage earners are eligible to participate. Additionally, the employee had to have made the maximum contribution allowable under the 401(k) Plan. Chesapeake matches 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 Company deferred compensation plans, including the Chesapeake 401(k) Plan, is a total of 75% of base salary and 100% of performance bonus. The Company contributed $9 million, $11 million and $7 million to the DC Plan during 2016, 2015 and 2014, respectively, to fund the match. Beginning in 2016, the DC Plan was no longer a spillover plan from the 401(k) Plan. The participant may choose separate deferral election percentages for both plans. 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 Chesapeake to fund future obligations of the Company's nonqualified deferred compensation plan is 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.

11. Derivative and Hedging Activities

Chesapeake uses derivative instruments to secure attractive pricing and margins on its share of expected production, to reduce its exposure to fluctuations in future commodity prices and to protect its expected operating cash flow against significant market movements or volatility. Chesapeake also uses derivative instruments to mitigate a portion of its exposure to foreign currency exchange rate fluctuations. All of our commodity derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

Oil, Natural Gas and NGL Derivatives

As of December 31, 2016 and 2015, our oil, natural gas and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we granted options that allow the counterparty to double the notional amount.
- *Options*: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty the excess on sold call options and Chesapeake receives the excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- *Collars*: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

The estimated fair values of our oil, natural gas and NGL derivative instrument assets (liabilities) as of December 31, 2016 and 2015 are provided below.

	December 31, 2016		December 31, 2015	
	Volume	Fair Value	Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	23	$ (140)	14	$ 144
Call options	5	(1)	19	(7)
Total oil	28	(141)	33	137
Natural gas (tbtu):				
Fixed-price swaps	719	(349)	500	229
Collars	60	(9)	—	—
Call options	114	—	295	(99)
Basis protection swaps	31	(5)	57	—
Total natural gas	924	(363)	852	130
NGL (mmgal):				
Fixed-price swaps	53	—	—	—
Total estimated fair value		$ (504)		$ 267

We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. See further discussion below under *Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)*.

Interest Rate Derivatives

As of December 31, 2016 and 2015, there were no interest rate derivatives outstanding.

We have terminated fair value hedges related to certain of our senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next four years, we will recognize $3 million in net gains related to these transactions.

Foreign Currency Derivatives

We are party to cross currency swaps to mitigate our exposure to foreign currency exchange rate fluctuations. During 2016, in connection with debt repurchases, we retired €56 million in aggregate principal amount of our 6.25% Euro-denominated Senior Notes due 2017, and we simultaneously unwound the cross currency swaps for the same principal amount at a cost of $13 million. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €8 million and we pay the counterparties $12 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €246 million and we will pay 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 are designated as cash flow hedges and, because they are entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value do not impact earnings. The fair values of the cross currency swaps are recorded on the consolidated balance sheets as liabilities of $73 million and $52 million as of December 31, 2016 and 2015, respectively. The euro-denominated debt in long-term debt has been adjusted to $258 million as of December 31, 2016, using an exchange rate of $1.0517 to €1.00.

Supply Contract Derivatives

From time to time and in the normal course of business, our marketing subsidiary enters into supply contracts under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas, thereby creating an embedded derivative requiring bifurcation. In one of these supply contracts, we were committed to supply a minimum of 90 bbtu per day of natural gas through March 2025. In 2016, we sold the long-term natural gas supply contract to a third party for cash proceeds of $146 million, which is included in marketing, gathering and compression revenues as a realized gain. Concurrent with this sale, we reversed the cumulative unrealized gains associated with this supply contract of $280 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, 2016 and 2015 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 Consolidated Balance Sheet
		($ in millions)	
As of December 31, 2016			
Commodity Contracts:			
Short-term derivative asset	$ 1	$ (1)	$ —
Short-term derivative liability	(490)	1	(489)
Long-term derivative liability	(15)	—	(15)
Total commodity contracts	(504)	—	(504)
Foreign Currency Contracts:[a]			
Short-term derivative liability	(73)	—	(73)
Total foreign currency contracts	(73)	—	(73)
Total derivatives	$ (577)	$ —	$ (577)
As of December 31, 2015			
Commodity Contracts:			
Short-term derivative asset	$ 381	$ (66)	$ 315
Short-term derivative liability	(106)	66	(40)
Long-term derivative liability	(8)	—	(8)
Total commodity contracts	267	—	267
Foreign Currency Contracts:[a]			
Long-term derivative liability	(52)	—	(52)
Total foreign currency contracts	(52)	—	(52)
Supply Contracts:			
Short-term derivative asset	51	—	51
Long-term derivative asset	246	—	246
Total supply contracts	297	—	297
Total derivatives	$ 512	$ —	$ 512

(a) Designated as cash flow hedging instruments.

As of December 31, 2016 and 2015, 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, 2016, 2015 and 2014 are presented below.

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Oil, natural gas and NGL revenues	$ 3,866	$ 4,767	$ 9,336
Gains (losses) on undesignated oil, natural gas and NGL derivatives	(545)	661	1,055
Losses on terminated cash flow hedges	(33)	(37)	(37)
Total oil, natural gas and NGL revenues	$ 3,288	$ 5,391	$ 10,354

The components of marketing, gathering and compression revenues for the years ended December 31, 2016, 2015 and 2014 are presented below.

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Marketing, gathering and compression revenues	$ 4,881	$ 7,077	$ 12,224
Gains (losses) on undesignated supply contract derivatives	(297)	296	1
Total marketing, gathering and compression revenues	$ 4,584	$ 7,373	$ 12,225

The components of interest expense for the years ended December 31, 2016, 2015 and 2014 are presented below.

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Interest expense on senior notes	$ 588	$ 682	$ 704
Interest expense on term loan	46	—	36
Amortization of loan discount, issuance costs and other	33	62	42
Amortization of premium associated with troubled debt restructuring	(165)	(3)	—
Interest expense on revolving credit facilities	35	12	28
Gains on terminated fair value hedges	(2)	(3)	(3)
(Gains) losses on undesignated interest rate derivatives	12	(9)	(81)
Capitalized interest	(251)	(424)	(637)
Total interest expense	$ 296	$ 317	$ 89

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,					
	2016		2015		2014	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (160)	$ (99)	$ (231)	$ (143)	$ (269)	$ (167)
Net change in fair value	(27)	(13)	32	20	1	1
Losses reclassified to income	34	16	39	24	37	23
Balance, end of period	$ (153)	$ (96)	$ (160)	$ (99)	$ (231)	$ (143)

Approximately $97 million of the accumulated other comprehensive loss as of December 31, 2016 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. Deferred gain or loss amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of December 31, 2016, we expect to transfer approximately $22 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amounts will be transferred by December 31, 2022.

Credit Risk Considerations

Our derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2016, our oil, natural gas and NGL and foreign currency derivative instruments were spread among 12 counterparties.

Hedging Arrangements

In 2015, we began entering into bilateral hedging agreements. The counterparties' and our obligations under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. In 2016, certain of our counterparties that are also lenders (or affiliates of our lenders) under our revolving credit facility entered into derivative contracts to be secured by the same collateral that secures the revolving credit facility. This allows us to reduce any letters of credit posted as security with those counterparties.

Fair Value

The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil, natural gas and NGL forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are compared to the values given by our counterparties for reasonableness. Since oil, natural gas, NGL, interest rate and cross currency swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. Derivatives are also subject to the risk that either party to a contract will be unable to meet its obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2016 and 2015:

	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, 2016				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 1	$ —	$ 1
Commodity liabilities	—	(495)	(10)	(505)
Foreign currency liabilities	—	(73)	—	(73)
Total derivatives	$ —	$ (567)	$ (10)	$ (577)
As of December 31, 2015				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 372	$ 9	$ 381
Commodity liabilities	—	(14)	(100)	(114)
Foreign currency liabilities	—	(52)	—	(52)
Supply contract assets	—	—	297	297
Total derivatives	$ —	$ 306	$ 206	$ 512

A summary of the changes in the fair values of Chesapeake's financial assets (liabilities) classified as Level 3 during 2016 and 2015 is presented below.

	Commodity Derivatives	Supply Contracts
	($ in millions)	
Beginning balance as of December 31, 2015	$ (91)	$ 297
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	6	(118)
Total purchases, issuances, sales and settlements:		
Settlements	75	(33)
Sales	—	(146)
Ending balance as of December 31, 2016	$ (10)	$ —
Beginning balance as of December 31, 2014	$ (54)	$ 1
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	100	316
Total purchases, issuances, sales and settlements:		
Settlements	(137)	(20)
Ending balance as of December 31, 2015	$ (91)	$ 297

(a)

	Oil, Natural Gas and NGL Sales		Marketing, Gathering and Compression Revenue	
	2016	2015	2016	2015
	($ in millions)			
Total gains (losses) included in earnings for the period	$ 6	$ 100	$ (118)	$ 316
Change in unrealized gains (losses) related to assets still held at reporting date	$ (7)	$ 43	$ —	$ 296

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

The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of natural gas, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts, which is based on an estimate derived from option models. For example, an increase or decrease in the forward prices and volatility of oil and natural gas prices decreases or increases the fair value of oil and natural gas derivatives, and adverse changes to our counterparties' creditworthiness decreases the fair value of our derivatives. The following table presents quantitative information about Level 3 inputs used in the fair value measurement of our commodity derivative contracts at fair value as of December 31, 2016:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2016
				($ in millions)
Oil trades	Oil price volatility curves	17.32% - 25.95%	23.95%	$ (1)
Natural gas trades	Natural gas price volatility curves	19.72% – 68.72%	30.71%	$ (9)

12. Oil and Natural Gas Property Transactions

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

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. 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. We may be required to pay additional amounts in respect of certain title and environmental contingencies. 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.

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.

2015 Transactions

CHK Cleveland Tonkawa, L.L.C. (CHK C-T) sold all of its oil and natural gas properties to FourPoint Energy, LLC and immediately used the consideration, plus other cash it had on hand, to repurchase and cancel all of CHK C-T's outstanding preferred shares. In a related transaction, we sold noncore properties adjacent to the CHK C-T properties to FourPoint Energy, LLC for approximately $90 million.

Excluding proceeds received from selling additional interests in our joint venture leasehold described under *Joint Ventures* below, we received proceeds related to divestitures of other noncore oil and natural gas properties of approximately $66 million.

2014 Transactions

We sold certain assets in the southern Marcellus Shale and a portion of the eastern Utica Shale to a subsidiary of Southwestern Energy Company for aggregate net proceeds of approximately $4.975 billion. We sold approximately 413,000 net acres and approximately 1,500 wells in northern West Virginia and southern Pennsylvania, of which 435 wells are in the Marcellus or Utica formations, along with related gathering assets and property, plant and equipment.

We exchanged interests in approximately 440,000 gross acres in the Powder River Basin in southeastern Wyoming with RKI Exploration & Production, LLC (RKI). Under the agreement, we conveyed to RKI approximately 137,000 net acres and our interest in 67 gross wells with an average working interest of approximately 22% in the northern portion of the Powder River Basin, where RKI was the designated operator. In exchange, RKI conveyed to us approximately 203,000 net acres and its interest in 186 gross wells with an average working interest of 48% in the southern portion of the Powder River Basin, where we were the designated operator. In conjunction with the exchange, we paid RKI approximately $450 million in cash.

We sold noncore leasehold interests in the Marcellus Shale to Rice Drilling B LLC, a wholly owned subsidiary of Rice Energy Inc. (NYSE:RICE), for net proceeds of $233 million.

We sold noncore leasehold interests, producing properties and 61 wellhead compressor units in South Texas to Hilcorp Energy Company for net proceeds of $133 million. Operating obligations related to VPP #5 were also transferred. See *Volumetric Production Payments* below.

We sold noncore leasehold interests and producing properties in East Texas and Louisiana for net proceeds of approximately $63 million. All commitments related to VPP #6 were also transferred. See *Volumetric Production Payments* below.

Excluding proceeds received from selling additional interests in our joint venture leasehold described under *Joint Ventures* below, we received proceeds related to divestitures of other noncore oil and natural gas properties of approximately $379 million.

Joint Ventures

In 2016, 2015 and 2014, we sold interests in additional leasehold we acquired in the Marcellus, Barnett, Utica, Eagle Ford shales and Mid-Continent plays to our joint venture partners for approximately $7 million, $33 million and $33 million, respectively.

Volumetric Production Payments

From time to time, we have sold certain of our producing assets located in more mature producing regions through the sale of VPPs. A VPP is a limited-term overriding royalty interest in oil and natural gas reserves that (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is non-recourse to the seller (i.e., the purchaser's only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered. For all of our VPP transactions, we novated to each of the respective VPP buyers hedges that covered all VPP volumes sold. If contractually scheduled volumes exceed the actual volumes produced from the VPP wellbores that are attributable to the ORRI conveyed, either the shortfall will be made up from future production from these wellbores (or, at our option, from our retained interest in the wellbores) through an adjustment mechanism, or the initial term of the VPP will be extended until all scheduled volumes, to the extent produced, are delivered from the VPP wellbores to the VPP buyer. We retain drilling rights on the properties below currently producing intervals and outside of producing wellbores.

As the operator of the properties from which the VPP volumes have been sold, we bear the cost of producing the reserves attributable to these interests, which we include as a component of production expenses and production taxes in our consolidated statements of operations in the periods these costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining our full cost ceiling test for impairment purposes and in determining our standardized measure. Pursuant to SEC guidelines, the estimates used for purposes of determining the cost center ceiling and the standardized measure are based on current costs. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which the production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all.

For accounting purposes, cash proceeds from the sale of VPPs were reflected as a reduction of oil and natural gas properties with no gain or loss recognized, and our proved reserves were reduced accordingly. We have also committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

As of December 31, 2016, we had the following VPP outstanding:

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

The volumes produced on behalf of our VPP buyers during 2016, 2015 and 2014 were as follows:

Year Ended December 31, 2016

VPP #	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	108.0	3.0	368.7	5.9
9	152.4	12.9	347.1	15.9
4[(a)]	20.0	3.8	—	3.9
3[(a)]	—	2.4	—	2.4
2[(a)]	—	1.5	—	1.5
1[(a)]	—	11.1	—	11.1
	280.4	34.7	715.8	40.7

Year Ended December 31, 2015

VPP #	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	310.0	8.5	1,043.9	16.6
9	167.9	14.2	375.9	17.4
8[(b)]	—	36.5	—	36.5
4[(a)]	42.5	8.0	—	8.2
3[(a)]	—	6.4	—	6.4
2[(a)]	—	4.0	—	4.0
1[(a)]	—	13.3	—	13.3
	520.4	90.9	1,419.8	102.4

Year Ended December 31, 2014

VPP #	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	403.0	10.6	1,296.5	20.7
9	187.5	15.4	411.0	19.0
8[(b)]	—	60.1	—	60.1
6[(c)]	23.1	4.2	—	4.3
5[(c)]	16.5	4.6	—	4.7
4[(a)]	48.1	9.0	—	9.2
3[(a)]	—	7.2	—	7.2
2[(a)]	—	6.2	—	6.2
1[(a)]	—	13.8	—	13.8
	678.2	131.1	1,707.5	145.2

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

(b) VPP #8 expired in August 2015.

(c) We divested the properties associated with VPP #5 and VPP #6 in 2014.

The volumes remaining to be delivered on behalf of our VPP buyers as of December 31, 2016 were as follows:

		Volume Remaining as of December 31, 2016			
VPP #	Term Remaining	Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	50	0.5	45.9	1.2	56.3

13. Spin-Off of Oilfield Services Business

On June 30, 2014, we completed the spin-off of our oilfield services business, which we previously conducted through our indirect, wholly owned subsidiary COO, into SSE, an independent, publicly traded company. Following the close of business on June 30, 2014, we distributed to Chesapeake shareholders one share of SSE common stock and cash in lieu of fractional shares for every 14 shares of Chesapeake common stock held on June 19, 2014, the record date for the distribution.

Prior to the completion of the spin-off, we and COO and its affiliates engaged in the following series of transactions:

- COO and certain of its subsidiaries entered into a $275 million senior secured revolving credit facility and a $400 million secured term loan, the proceeds of which were used to repay in full and terminate COO's then-existing credit facility.
- COO distributed to us its compression unit manufacturing business, its geosteering business and the proceeds from the sale of substantially all of its crude oil hauling business.
- We transferred to a subsidiary of COO, at carrying value, certain of our buildings and land, most of which COO had been leasing from us prior to the spin-off.
- COO issued $500 million of 6.5% Senior Notes due 2022 in a private placement and used the net proceeds to make a cash distribution of approximately $391 million to us, to repay a portion of outstanding indebtedness under the new revolving credit facility and for general corporate purposes.

Following the spin-off, we have no ownership interest in SSE. Therefore, we ceased to consolidate SSE's assets and liabilities as of the spin-off date. Because we expect to have significant continued involvement associated with SSE's future operations through the various agreements we entered into in connection with the spin-off, our former oilfield services segment's historical financial results for periods prior to the spin-off continue to be included in our historical financial results as a component of continuing operations. For segment disclosures, we have labeled our oilfield services segment as "Former Oilfield Services". See Note 21 for additional information regarding our segments.

In 2014, our stockholders' equity decreased by $270 million, net of $151 million of associated deferred tax liabilities, as a result of the spin-off, and we recognized $15 million of charges associated with the spin-off that are included in restructuring and other termination costs on our consolidated statement of operations.

14. Investments

A summary of our investments, including our approximate ownership percentage and carrying value as of December 31, 2016 and 2015, is presented below.

	Accounting Method	Approximate Ownership % December 31, 2016	Approximate Ownership % December 31, 2015	Carrying Value December 31, 2016	Carrying Value December 31, 2015
				($ in millions)	
Sundrop Fuels, Inc.	Equity	56%	56%	$ —	$ 119
FTS International, Inc.	Equity	30%	30%	—	—
Other	—	—%	—%	7	17
Total investments[(a)]				$ 7	$ 136

(a) Balance is included in other long-term assets on our consolidated balance sheets.

Sundrop Fuels, Inc. Sundrop Fuels, Inc. (Sundrop), based in Longmont, Colorado, is a privately held cellulosic biofuels company that is constructing a nonfood biomass-based “green gasoline” plant. Based on our review of the investment in Sundrop, we recognized an other-than-temporary impairment of $119 million in 2016. In 2015, we recorded a $20 million charge related to our share of Sundrop's net loss and $9 million of capitalized interest associated with the construction of Sundrop’s plant.

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company that, through its subsidiaries, provides hydraulic fracturing and other services to oil and gas companies. In 2015, we recorded our equity in FTS’ net losses and other adjustments, prior to intercompany profit eliminations, of $107 million and an accretion adjustment of $44 million related to the excess of our underlying equity in net assets of FTS over our carrying value. Due to the decrease in the oil and natural gas pricing environment, we recognized an other-than-temporary impairment on our investment in FTS of $53 million during 2015.

Sold Investments

Chaparral Energy, Inc. Chaparral Energy, Inc. (Chaparral), based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties. In 2014, we sold all of our interest in Chaparral for net cash proceeds of $209 million. We recorded a $73 million gain related to the sale.

Other. In 2014, we sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction.

15. Variable Interest Entities

We consolidate the activities of VIEs for which we are the primary beneficiary. In order to determine whether we own a variable interest in a VIE, we perform qualitative analysis of the entity's design, organizational structure, primary decision makers and relevant agreements.

Consolidated VIE

Chesapeake Granite Wash Trust (the Trust) is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Trust and because the royalty interest owners, other than Chesapeake, do not have the ability to exercise substantial liquidation rights. Our ownership in the Trust and our previous obligations under the development agreement constitute variable interests. We have determined that we are the primary beneficiary of the Trust because (i) we have the power to direct the activities that most significantly impact the economic performance of the Trust via our operation of the majority of the producing wells and the completed development wells, and (ii) as a result of the subordination and incentive thresholds applicable to the subordinated units we hold in the Trust, we have the obligation to absorb losses and the right to receive residual returns that potentially could be significant to the Trust. As a result, we consolidate the Trust in our financial statements, and the common units of the Trust owned by third parties are reflected as a noncontrolling interest.

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries, and the Trust is not a guarantor of any of Chesapeake's debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake. In consolidation, as of December 31, 2016, $1 million of cash and cash equivalents, $488 million of proved oil and natural gas properties, $458 million of accumulated depreciation, depletion and amortization and $3 million of other current liabilities were attributable to the Trust. 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.

Unconsolidated VIE

Mineral Acquisition Company I, L.P. In 2012, MAC-LP, L.L.C., a wholly owned non-guarantor unrestricted subsidiary of Chesapeake, entered into a partnership agreement with KKR Royalty Aggregator LLC (KKR) to form Mineral Acquisition Company I, L.P. The purpose of the partnership was to acquire mineral interests, or royalty interests carved out of mineral interests, in oil and natural gas basins in the continental United States. The partnership was an unconsolidated VIE and the carrying value of our equity investment was $10 million as of December 31, 2015. During 2016, we sold certain mineral interests held outside the partnership for approximately $9 million, and assigned our interest in the partnership to KKR, which eliminated our future commitments to acquire additional mineral interests. As a result of the transaction, we wrote off our equity investment and recognized a $10 million loss which is included in net gain (loss) on sales of investments in our consolidated statements of operations.

16. 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, 2016	December 31, 2015	Estimated Useful Life
	($ in millions)		(in years)
Buildings and improvements	$ 1,119	$ 1,209	10 – 39
Computer equipment	337	318	5
Natural gas compressors[(a)]	251	483	3 – 20
Land	139	289	
Gathering systems and treating plants[(a)]	2	214	20
Other	205	414	2 – 20
Total other property and equipment, at cost	2,053	2,927	
Less: accumulated depreciation	(632)	(813)	
Total other property and equipment, net	$ 1,421	$ 2,114	

(a) Included in our marketing, gathering and compression operating segment. The decrease is primarily related to asset divestitures in 2016.

Net (Gains) Losses on Sales of Fixed Assets

A summary by asset class of (gains) or losses on sales of fixed assets for the years ended December 31, 2016, 2015 and 2014 is as follows:

	Years Ended December 31, 2016	2015	2014
		($ in millions)	
Buildings and land	$ (1)	$ 3	$ (2)
Natural gas compressors	(10)	—	(195)
Gathering systems and treating plants	—	1	8
Oilfield services equipment	—	—	(7)
Other	(1)	—	(3)
Total net (gains) losses on sales of fixed assets	$ (12)	$ 4	$ (199)

Natural Gas Compressors. In 2014, we sold 703 compressors to various parties for $693 million and recorded an aggregate gain of $195 million on the sales.

Assets Held for Sale

We are continuing to pursue the sale of buildings and land located primarily in Oklahoma and West Virginia. Buildings and land are recorded within our other segment. These assets are being actively marketed, and we believe it is probable they will be sold over the next 12 months. As a result, these assets are reflected as held for sale as of December 31, 2016. Oil and natural gas properties that we intend to sell are not presented as held for sale pursuant to the rules governing full cost accounting for oil and gas properties. As of December 31, 2016 and 2015, we had $29 million and $95 million, respectively, of buildings and land, net of accumulated depreciation, classified as assets held for sale on our consolidated balance sheets.

17. Impairments

Impairments of Oil and Natural Gas Properties

Our proved oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. Estimated future net revenues for the quarterly ceiling limit are calculated using the average of commodity prices on the first day of the month over the trailing 12-month period. In 2016 and 2015, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments in the carrying value of our oil and natural gas properties of $2.564 billion and $18.238 billion, respectively. In 2014, we did not have an impairment for our oil and natural gas properties. Cash flow hedges which relate to future periods increased the ceiling test impairment by $176 million in 2015.

Impairments of Fixed Assets and Other

We review our long-lived assets, other than oil and natural gas properties, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable. We recognize an impairment if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. A summary of our impairments of fixed assets by asset class and other charges for the years ended December 31, 2016, 2015 and 2014 is as follows:

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Barnett Shale exit costs	$ 645	$ —	$ —
Devonian Shale exit costs	142	—	—
Gathering systems	3	—	13
Natural gas compressors	21	21	11
Buildings and land	11	—	18
Oilfield services equipment	—	—	23
Other	16	173	23
Total impairments of fixed assets and other	$ 838	$ 194	$ 88

Barnett Shale Exit Costs. 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. We also recognized an impairment charge of $284 million in 2016 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.

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

Oilfield Services Equipment. In 2014, we purchased 31 leased rigs and equipment from various lessors for an aggregate purchase price of $140 million. In connection with these purchases, we paid $8 million in early lease termination costs, which are included in impairments of fixed assets and other in the consolidated statement of operations. In addition, we recognized an impairment loss of approximately $15 million related to leasehold improvements associated with these assets. The drilling rigs and equipment are included in our former oilfield services operating segment.

Other. In 2015, we recorded a $47 million loss contingency related to contract disputes. In 2015, we recorded a $22 million impairment of a note receivable as a result of the increased credit risk associated with declining commodity prices. In addition, under the terms of our joint venture agreements (see Note 12), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas. In 2015, we entered into a settlement with Total regarding our acreage maintenance commitment in our Barnett Shale joint venture and accrued a $70 million charge. In 2015, as a result of reductions in our planned drilling activity in response to declines in oil and natural gas prices, we terminated contracts with drilling contractors and incurred charges of $18 million. The contract termination charges are included in our exploration and production operating segment. In 2014, we revised our estimate of our net acreage shortfall with Total under the terms of our Barnett Shale joint venture agreement and recorded a $22 million charge. See Note 4 for additional discussion regarding our net acreage maintenance commitments.

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

18. Restructuring and Other Termination Costs

Workforce Reductions

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.

On September 29, 2015, we reduced our workforce by approximately 15% as part of an overall plan to reduce costs and better align our workforce with the needs of our business and current oil and natural gas commodity prices. In connection with the reduction, we incurred a total charge of approximately $55 million in 2015 for one-time termination benefits. This charge consisted of $47 million in salary expense and $8 million in other termination benefits.

Oilfield Services Spin-Off

On June 30, 2014, we completed the spin-off of our oilfield services business through a pro rata distribution of SSE common stock to holders of Chesapeake common stock. In connection with the spin-off, in 2014, we incurred restructuring charges of $15 million, including transaction costs of $17 million, stock-based compensation adjustments of $5 million for Chesapeake employees, credits of $10 million of forfeitures for Seventy Seven Energy employees and $3 million in debt extinguishment costs. See Note 13 for further discussion of the spin-off.

Other

We recognized credits of $19 million and $8 million in 2015 and 2014, respectively, related to negative fair value adjustments to PSUs granted to former executives of the Company which corresponded to a decrease in the trading price of our common stock. For further discussion of our PSUs, see Note 9.

19. Fair Value Measurements

Recurring Fair Value Measurements

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

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

Financial Assets (Liabilities). The following table provides fair value measurement information for the above-noted financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2016 and 2015:

	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, 2016				
Financial Assets (Liabilities):				
Other current assets	$ 49	$ —	$ —	$ 49
Other current liabilities	(51)	—	—	(51)
Total	$ (2)	$ —	$ —	$ (2)
As of December 31, 2015				
Financial Assets (Liabilities):				
Other current assets	$ 50	$ —	$ —	$ 50
Other current liabilities	(51)	—	—	(51)
Total	$ (1)	$ —	$ —	$ (1)

See Note 3 for information regarding fair value measurement of our debt instruments. See Note 11 for information regarding fair value measurement of our derivatives.

Nonrecurring Fair Value Measurements

See Note 17 regarding nonrecurring fair value measurements.

20. Asset Retirement Obligations

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

	Years Ended December 31,	
	2016	2015
	($ in millions)	
Asset retirement obligations, beginning of period	$ 473	$ 465
Additions	4	6
Revisions[(a)]	(58)	13
Settlements and disposals[(b)]	(182)	(34)
Accretion expense	24	23
Asset retirement obligations, end of period	261	473
Less current portion [(c)]	14	21
Asset retirement obligation, long-term	$ 247	$ 452

(a) Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and the expected timing of settlement.

(b) Settlements and disposals in 2016 relate primarily to wells divested in the Barnett and Devonian Shale areas.

(c) Balance is included in other current liabilities on our consolidated balance sheets.

21. Major Customers and Segment Information

Sales to BP PLC constituted approximately 10% and 14% of our total revenues (before the effects of hedging) for the years ended December 31, 2016 and 2015, respectively. Sales to Exxon Mobil Corporation constituted approximately 12% of our total revenues (before the effects of hedging) for the year ended December 31, 2014.

As of December 31, 2016, we have two reportable operating segments, each of which is managed separately because of the nature of its operations. The exploration and production operating segment is responsible for finding and producing oil, natural gas and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of oil, natural gas and NGL. In addition, prior to the spin-off of our oilfield services business in June 2014, our former oilfield services operating segment was responsible for drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services for both Chesapeake-operated wells and wells operated by third parties. Our former oilfield services segment's historical financial results for periods prior to the spin-off continue to be included in our historical financial results as a component of continuing operations, as reflected in the table below.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of oil, natural gas and NGL related to Chesapeake's ownership interests by our marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. These amounts totaled $3.750 billion, $4.372 billion and $8.565 billion for the years ended December 31, 2016, 2015 and 2014, respectively. Revenues generated by our former oilfield services operating segment for work performed for Chesapeake's exploration and production operating segment were reclassified to the full cost pool based on Chesapeake's ownership interest. Revenues reclassified totaled $544 million for year ended December 31, 2014. No income was recognized in our consolidated statements of operations related to oilfield services performed for Chesapeake-operated wells.

During the 2016 first quarter, we changed the structure of our internal organization to include certain assets in our Exploration and Production reportable segment instead of our Other segment. Accordingly, this change has been reflected through retroactive revision of the segment information as of December 31, 2015 and 2014, as shown in the tables below.

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

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
			($ in millions)			
Year Ended December 31, 2016						
Revenues	$ 3,288	$ 8,334	$ —	$ —	$ (3,750)	$ 7,872
Intersegment revenues	—	(3,750)	—	—	3,750	—
Total revenues	$ 3,288	$ 4,584	$ —	$ —	$ —	$ 7,872
Unrealized losses on commodity derivatives	$ 819	$ —	$ —	$ —	$ —	$ 819
Unrealized losses on marketing derivatives	$ —	$ 297	$ —	$ —	$ —	$ 297
Oil, natural gas, NGL and other depreciation, depletion and amortization	$ 1,024	$ 45	$ —	$ 38	$ —	$ 1,107
Impairment of oil and natural gas properties	$ 2,564	$ —	$ —	$ —	$ —	$ 2,564
Impairments of fixed assets and other	$ 387	$ 220	$ —	$ 231	$ —	$ 838
Net gain (loss) on sales of fixed assets	$ (4)	$ (7)	$ —	$ (1)	$ —	$ (12)
Interest expense	$ (303)	$ —	$ —	$ 7	$ —	$ (296)
Losses on investments	$ —	$ —	$ —	$ (8)	$ —	$ (8)
Impairments of investments	$ —	$ —	$ —	$ (119)	$ —	$ (119)
Gains on purchases or exchanges of debt	$ 236	$ —	$ —	$ —	$ —	$ 236
Income (Loss) Before Income Taxes	$ (4,099)	$ (112)	$ —	$ (378)	$ —	$ (4,589)
Total Assets	$ 11,249	$ 1,118	$ —	$ 1,059	$ (398)	$ 13,028
Capital Expenditures	$ 1,439	$ 7	$ —	$ —	$ —	$ 1,446

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Year Ended December 31, 2015						
Revenues	$ 5,391	$ 11,745	$ —	$ —	$ (4,372)	$ 12,764
Intersegment revenues	—	(4,372)	—	—	4,372	—
Total revenues	$ 5,391	$ 7,373	$ —	$ —	$ —	$ 12,764
Unrealized losses on commodity derivatives	$ 693	$ —	$ —	$ —	$ —	$ 693
Unrealized gains on marketing derivatives	$ —	$ (295)	$ —	$ —	$ —	$ (295)
Oil, natural gas, NGL and other depreciation, depletion and amortization	$ 2,170	$ 20	$ —	$ 39	$ —	$ 2,229
Impairment of oil and natural gas properties	$ 18,238	$ —	$ —	$ —	$ —	$ 18,238
Impairments of fixed assets and other	$ 126	$ 68	$ —	$ —	$ —	$ 194
Net gain (loss) on sales of fixed assets	$ 1	$ 1	$ —	$ 2	$ —	$ 4
Interest expense	$ (925)	$ (4)	$ —	$ 6	$ 606	$ (317)
Losses on investments	$ (3)	$ —	$ —	$ (93)	$ —	$ (96)
Impairments of investments	$ —	$ —	$ —	$ (53)	$ —	$ (53)
Gains on purchases or exchanges of debt	$ 279	$ —	$ — —	$ —	$ —	$ 279
Income (Loss) Before Income Taxes	$ (19,619)	$ 117	$ —	$ (127)	$ 531	$ (19,098)
Total Assets (as previously reported)	$ 11,776	$ 1,524	$ —	$ 4,325	$ (311)	$ 17,314
Total Assets (as revised)	$ 14,610	$ 1,524	$ —	$ 1,491	$ (311)	$ 17,314
Capital Expenditures	$ 3,562	$ 42	$ —	$ 10	$ —	$ 3,614

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Year Ended December 31, 2014						
Revenues	$ 10,354	$ 20,790	$ 1,060	$ 30	$ (9,109)	$ 23,125
Intersegment revenues	—	(8,565)	(544)	—	9,109	—
Total revenues	$ 10,354	$ 12,225	$ 516	$ 30	$ —	$ 23,125
Unrealized losses on commodity derivatives	$ (1,394)	$ —	$ —	$ —	$ —	$ (1,394)
Unrealized gains on marketing derivatives	$ —	$ (3)	$ —	$ —	$ —	$ (3)
Oil, natural gas, NGL and other depreciation, depletion and amortization	$ 2,756	$ 38	$ 145	$ 42	$ (66)	$ 2,915
Impairments of fixed assets and other	$ 22	$ 24	$ 23	$ 19	$ —	$ 88
Net gain (loss) on sales of fixed assets	$ (2)	$ (187)	$ (8)	$ (2)	$ —	$ (199)
Interest expense	$ (709)	$ (21)	$ (42)	$ 3	$ 680	$ (89)
Losses on investments	$ 2	$ —	$ (1)	$ (76)	$ —	$ (75)
Impairments of investments	$ —	$ —	$ (5)	$ —	$ —	$ (5)
Net loss on sales of investments	$ (6)	$ —	$ —	$ 73	$ —	$ 67
Gains on purchases or exchanges of debt	$ (197)	$ —	$ —	$ —	$ —	$ (197)
Income (Loss) Before Income Taxes	$ 2,874	$ 326	$ (16)	$ (30)	$ 46	$ 3,200
Total Assets (as previously reported)	$ 35,285	$ 1,978	$ —	$ 4,283	$ (891)	$ 40,655
Total Assets (as revised)	$ 38,012	$ 1,978	$ —	$ 1,556	$ (891)	$ 40,655
Capital Expenditures	$ 6,173	$ 298	$ 158	$ 38	$ —	$ 6,667

22. Recently Issued Accounting Standards

In May 2014, the FASB issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration the company expects to receive in the exchange. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early application not permitted. In July 2015, the FASB approved a one-year deferral of the effective date as well as permission to early adopt the new revenue recognition standard as of the original effective date. In March 2016, the FASB issued an update clarifying the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued an update clarifying the identification of performance obligations and licensing implementations guidance. In May 2016, the FASB issued an update clarifying guidance in a few narrow areas and added some practical expedients to the guidance. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In August 2014, the FASB issued updated guidance that requires management, for each annual and interim reporting period, to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the consolidated financial statements are issued. If management concludes that conditions or events raise substantial doubt about the entity's ability to continue as a going concern, certain disclosures are required to be made within the footnotes to the consolidated financial statements. The amendments in this update are effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted. We adopted this guidance as of December 31, 2016, and it had no impact on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued updated lease accounting guidance requiring companies to recognize the assets and liabilities for the rights and obligations created by long-term leases of assets on the balance sheet. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued guidance for improvements to employee share-based payment accounting to simplify the accounting for share-based compensation. The new standard requires all excess tax benefits and reductions from differences between the deduction for tax purposes and the compensation cost recorded for financial reporting purposes be recognized as income tax expense or benefit in the income statement and not recognized as additional paid-in capital. The new standard also requires all excess tax benefits and deficiencies to be classified as operating activity within the statement of cash flows. For public business entities, the amendments are effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2016. Early adoption is permitted in any interim or annual period, with any adjustments reflected as of the beginning of the fiscal year of adoption. We have elected to early adopt the amendments effective January 1, 2016. The cumulative-effect adjustment to retained earnings for all excess tax benefits not previously recognized as of the beginning period is fully offset by a corresponding change in the valuation allowance resulting in no change to our consolidated financial statements. The implementation of this guidance did not have a material impact on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued new guidance that will result in fewer put or call options embedded in debt instruments qualifying for separate derivative accounting because companies will not be required to assess whether the contingent event, such as change in control or an IPO, is related to interest rates or credit risks. This standard is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

23. Subsequent Events

In January 2017, we purchased and retired approximately $287 million principal amount of our outstanding contingent convertible senior notes and $2 million principal amount of our outstanding senior notes for an aggregate of $286 million pursuant to tender offers.

In January 2017, we completed private exchanges of an aggregate of approximately 10.0 million shares of our common stock for (i) 150,948 shares of 5.00% Cumulative Convertible Preferred Stock (Series 2005B), (ii) 72,600 shares of 5.75% Cumulative Convertible Preferred Stock and (iii) 12,500 shares of 5.75% Cumulative Convertible Preferred Stock (Series A).

In January 2017, we sold a portion of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $450 million, subject to certain customary post-closing adjustments. Included in the sale were approximately 78,000 net acres. The sale also included 250 wells currently producing approximately 30 mmcf of gas per day.

In January 2017, we redeemed our $133 million principal amount of outstanding 6.5% Senior Notes due 2017.

In January 2017, we repurchased in the open market approximately $221 million principal amount of our outstanding debt scheduled to mature or that could be put to us in 2018 and 2020 for $224 million.

In February 2017, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock and paid our dividends in arrears.

In February 2017, we sold a portion of our acreage and producing properties in our Haynesville Shale operating area in northern Louisiana for approximately $465 million, subject to certain customary post-closing adjustments. Included in the sale were approximately 41,500 net acres. The sale also included 326 operated and non-operated wells currently producing approximately 50 mmcf of gas per day.

In February 2017, we paid $290 million to assign an oil transportation agreement. This assignment is expected to reduce our future oil transportation commitments by approximately $450 million. The assignment is effective April 1, 2017. In addition, we terminated future natural gas transportation commitments related to divested assets of approximately $110 million for a cash payment of approximately $100 million. This termination was effective March 1, 2017.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
SUPPLEMENTARY INFORMATION

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2016 and 2015 are as follows:

2016 First Quarter	As Previously Reported	Adjustment[b]	As Revised
	($ in millions except per share data)		
Total revenues	$ 1,953	$ —	$ 1,953
Gross profit[a]	$ (952)	$ (147)	$ (1,099)
Net loss attributable to Chesapeake	$ (921)	$ (147)	$ (1,068)
Net loss available to common stockholders	$ (964)	$ (147)	$ (1,111)
Net loss per common share:			
Basic	$ (1.44)	$ (0.21)	$ (1.65)
Diluted	$ (1.44)	$ (0.21)	$ (1.65)

2016 Second Quarter	As Previously Reported	Adjustment[b]	As Revised
	($ in millions except per share data)		
Total revenues	$ 1,622	$ —	$ 1,622
Gross profit[a]	$ (1,757)	$ (26)	$ (1,783)
Net loss attributable to Chesapeake	$ (1,750)	$ (26)	$ (1,776)
Net loss available to common stockholders	$ (1,792)	$ (26)	$ (1,818)
Net loss per common share:			
Basic	$ (2.48)	$ (0.05)	$ (2.53)
Diluted	$ (2.48)	$ (0.05)	$ (2.53)

2016 Third Quarter	As Previously Reported	Adjustment[b]	As Revised
	($ in millions except per share data)		
Total revenues	$ 2,276	$ —	$ 2,276
Gross profit[a]	$ (1,174)	$ (60)	$ (1,234)
Net loss attributable to Chesapeake	$ (1,155)	$ (60)	$ (1,215)
Net loss available to common stockholders	$ (1,197)	$ (60)	$ (1,257)
Net loss per common share:			
Basic	$ (1.54)	$ (0.08)	$ (1.62)
Diluted	$ (1.54)	$ (0.08)	$ (1.62)

2016 Fourth Quarter	
	($ in millions)
Total revenues	$ 2,021
Gross profit[a]	$ (295)
Net loss attributable to Chesapeake	$ (342)
Net loss available to common stockholders	$ (740)
Net loss per common share:	($ per share)
Basic	$ (0.83)
Diluted	$ (0.83)

	2015 First Quarter		2015 Second Quarter		2015 Third Quarter		2015 Fourth Quarter	
	($ in millions except per share data)							
Total revenues	$	3,218	$	3,521	$	3,376	$	2,649
Gross profit[(a)]	$	(5,040)	$	(5,507)	$	(5,453)	$	(2,919)
Net loss attributable to Chesapeake	$	(3,739)	$	(4,108)	$	(4,653)	$	(2,185)
Net loss available to common stockholders	$	(3,782)	$	(4,151)	$	(4,695)	$	(2,228)
Net loss per common share:								
Basic	$	(5.72)	$	(6.27)	$	(7.08)	$	(3.36)
Diluted	$	(5.72)	$	(6.27)	$	(7.08)	$	(3.36)

(a) Total revenue less operating expenses. Includes $2.564 billion and $18.238 billion in ceiling test write-downs on our oil and natural gas properties for the years ended December 31, 2016 and 2015, respectively.

(b) During our review of the full cost ceiling test calculation for the fourth quarter of 2016, we identified certain errors to the basis price differentials used in calculating the impairment of oil and natural gas properties and oil, natural gas and NGL depreciation, depletion and amortization for each of the first three interim periods in 2016. We determined that these errors do not relate to periods prior to January 1, 2016.

The impact of the errors was an understatement in the impairment of oil and natural gas properties of $144 million for the quarter ended March 31, 2016, $24 million for the quarter ended June 30, 2016 and $64 million for the quarter ended September 30, 2016. The impact of the error was also an overstatement in the oil, natural gas and NGL depreciation, depletion and amortization of $8 million for the quarter ended March 31, 2016, an understatement of $13 million for the quarter ended June 30, 2016 and an overstatement of $4 million for the quarter ended September 30, 2016. In accordance with Staff Accounting Bulletin No. 99, *Materiality*, management evaluated the materiality of the errors from qualitative and quantitative perspectives and concluded that the errors are not material to our previously issued interim financial statements. Accordingly, the corrections for these errors and an other immaterial previously identified error is reflected in the table above. The corrections associated with these errors will also be reflected in our 2017 Form 10-Q filings.

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

Net Capitalized Costs

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

	December 31, 2016	December 31, 2015
	($ in millions)	
Oil and oil and natural gas properties:		
Proved	$ 66,451	$ 63,843
Unproved	4,802	6,798
Total	71,253	70,641
Less accumulated depreciation, depletion and amortization	(62,094)	(58,552)
Net capitalized costs	$ 9,159	$ 12,089

Unproved properties not subject to amortization as of December 31, 2016 and 2015, consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. We capitalized approximately $242 million, $410 million and $604 million of interest during 2016, 2015 and 2014, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full cost pool. 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, 2016	2015	2014
		($ in millions)	
Acquisition of Properties:			
Proved properties	$ 403	$ —	$ 214
Unproved properties	403	454	1,224
Exploratory costs	52	112	421
Development costs	1,312	2,941	4,204
Costs incurred[(a)(b)]	$ 2,170	$ 3,507	$ 6,063

(a) Exploratory and development costs are net of $51 million and $679 million in drilling and completion carries received from our joint venture partners during 2015 and 2014, respectively.

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

Capitalized interest	$ 242	$ 410	$ 604
Asset retirement obligations	$ (57)	$ (15)	$ 39

In 2016, we invested approximately $312 million, to convert 118 mmboe of PUDs to proved developed reserves.

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

Chesapeake's results of operations from oil, natural gas and NGL producing activities are presented below for 2016, 2015 and 2014. 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,		
	2016	2015	2014
	($ in millions)		
Oil, natural gas and NGL sales	$ 3,288	$ 5,391	$ 10,354
Oil, natural gas and NGL production expenses	(710)	(1,046)	(1,208)
Oil, natural gas and NGL gathering, processing and transportation expenses	(1,855)	(2,119)	(2,174)
Production taxes	(74)	(99)	(232)
Impairment of oil and natural gas properties	(2,564)	(18,238)	—
Depletion and depreciation	(1,003)	(2,099)	(2,683)
Imputed income tax provision[(a)]	1,027	6,683	(1,485)
Results of operations from oil, natural gas and NGL producing activities	$ (1,891)	$ (11,527)	$ 2,572

(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

Chesapeake's petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2016, 2015 and 2014. Independent petroleum engineering firms estimated an aggregate of 70%, 59% and 79% of our estimated proved reserves (by volume) as of December 31, 2016, 2015 and 2014, respectively, as set forth below.

	December 31,		
	2016	2015	2014
Ryder Scott Company, L.P.	—%	36%	54%
Software Integrated Solutions, Division of Schlumberger Technology Corporation	70%	23%	25%

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 2016, 2015 and 2014.

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
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[(a)]	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

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
December 31, 2015				
Proved reserves, beginning of period	420.8	10,692	266.3	2,469
Extensions, discoveries and other additions	61.1	805	35.3	231
Revisions of previous estimates	(110.0)	(4,191)	(75.8)	(885)
Production	(41.6)	(1,070)	(28.0)	(248)
Sale of reserves-in-place	(16.6)	(195)	(14.3)	(63)
Purchase of reserves-in-place	—	—	—	—
Proved reserves, end of period[c]	313.7	6,041	183.5	1,504
Proved developed reserves:				
Beginning of period	229.3	8,615	198.5	1,864
End of period	215.6	5,329	158.0	1,262
Proved undeveloped reserves:				
Beginning of period	191.5	2,077	67.8	605
End of period[b]	98.1	712	25.5	242
December 31, 2014				
Proved reserves, beginning of period	423.8	11,734	299.0	2,678
Extensions, discoveries and other additions	108.6	1,567	78.2	448
Revisions of previous estimates	(51.1)	(129)	21.3	(51)
Production	(42.3)	(1,095)	(33.1)	(258)
Sale of reserves-in-place	(23.3)	(1,421)	(101.7)	(362)
Purchase of reserves-in-place	5.1	36	2.6	14
Proved reserves, end of period[d]	420.8	10,692	266.3	2,469
Proved developed reserves:				
Beginning of period	201.3	8,584	177.1	1,809
End of period	229.3	8,615	198.5	1,864
Proved undeveloped reserves:				
Beginning of period	222.5	3,150	121.9	869
End of period[b]	191.5	2,077	67.8	605

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

(b) As of December 31, 2016, 2015 and 2014, there were no PUDs that had remained undeveloped for five years or more.

(c) Includes 1 mmbbl of oil, 32 bcf of natural gas and 3 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 1 mmbbl of oil, 16 bcf of natural gas and 2 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

(d) Includes 2 mmbbls of oil, 46 bcf of natural gas and 5 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 1 mmbbl of oil, 22 bcf of natural gas and 2 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

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 the 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.

During 2015, we sold 63 mmboe of proved reserves for approximately $97 million plus the cancellation of all of CHK C-T's outstanding preferred shares. See Note 12 to our consolidated financial statements included in Item 8 of this report for further discussion of oil and natural gas property transactions. We recorded downward revisions of 885 mmboe, which was comprised of a 1,098 mmboe decrease, resulting primarily from lower oil, natural gas and NGL prices in 2015, partially offset by 213 mmboe of upward revisions resulting from changes in previous estimates. The oil and natural gas prices used in computing our reserves as of December 31, 2015, were $50.28 per bbl and $2.58 per mcf, respectively, before price differentials.

During 2014, we acquired approximately 14 mmboe of proved reserves through purchases of oil and natural gas properties for consideration of $168 million, and we sold 362 mmboe of proved reserves for approximately $4.7 billion. We recorded downward revisions of 51 mmboe, including a 78 mmboe reduction in previous estimates partially offset by a 27 mmboe increase, primarily the result of higher natural gas prices in 2014. The oil and natural gas prices used in computing our reserves as of December 31, 2014, were $94.98 per bbl and $4.35 per mcf, respectively, before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2014 were $89.09 per barrel of oil, $2.68 per mcf of natural gas and $24.10 per barrel of NGL.

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, 2016, 2015 and 2014 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,		
	2016	2015	2014
	($ in millions)		
Future cash inflows	$ 19,835 [(a)]	$ 20,247 [(b)]	$ 72,557 [(c)]
Future production costs	(6,800)	(7,391)	(17,036)
Future development costs	(3,621)	(1,518)	(7,556)
Future income tax provisions	(79)	(228)	(12,494)
Future net cash flows	9,335	11,110	35,471
Less effect of a 10% discount factor	(4,956)	(6,417)	(18,338)
Standardized measure of discounted future net cash flows[(d)]	$ 4,379	$ 4,693	$ 17,133

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

(b) Calculated using prices of $50.28 per bbl of oil and $2.58 per mcf of natural gas, before field differentials.

(c) Calculated using prices of $94.98 per bbl of oil and $4.35 per mcf of natural gas, before field differentials.

(d) Excludes future cash inflows attributable to production volumes sold to VPP buyers and includes future cash outflows attributable to the costs of production. See Note 12.

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

	Years Ended December 31,		
	2016	2015	2014
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 4,693	$ 17,133	$ 17,390
Sales of oil and natural gas produced, net of production costs and gathering, processing and transportation[(b)]	(1,227)	(1,503)	(5,722)
Net changes in prices and production costs	(1,210)	(18,070)	(634)
Extensions and discoveries, net of production and development costs	1,042	1,005	5,156
Changes in estimated future development costs	323	3,198	1,946
Previously estimated development costs incurred during the period	664	873	1,178
Revisions of previous quantity estimates	145	(3,472)	(715)
Purchase of reserves-in-place	394	1	215
Sales of reserves-in-place	13	(938)	(1,788)
Accretion of discount	473	2,201	2,168
Net change in income taxes	(8)	4,845	(593)
Changes in production rates and other	(923)	(580)	(1,468)
Standardized measure, end of period[(a)(c)(d)]	$ 4,379	$ 4,693	$ 17,133

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

(b) Excluding gains (losses) on derivatives.

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

(d) The standardized measure of discounted future net cash flows does not include estimated future cash inflows attributable to future production of VPP volumes sold and does include estimated future cash outflows attributable to the costs of future production of VPP volumes sold.

ITEM 9. *Changes In and Disagreements with Accountants on Accounting and Financial Disclosure*

Not applicable.

ITEM 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15 (b). Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were not effective as of December 31, 2016 because of the material weakness in our internal control over financial reporting described in Management's Report on Internal Control Over Financial Reporting appearing under Item 8 of Part II of this Annual Report on Form 10-K.

Our Chief Executive Officer and Chief Financial Officer also determined that the material weakness existed at March 31, 2016, June 30, 2016, and September 30, 2016 and therefore, they also concluded that we did not maintain effective disclosure controls and procedures as of those dates. Notwithstanding such material weakness in internal control over financial reporting, our Chief Executive Officer and Chief Financial Officer have concluded that the unaudited condensed consolidated financial statements included in the Form 10-Q filings for reporting periods ended March 31, 2016, June 30, 2016, and September 30, 2016 present fairly, in all material respects, our financial position, results of operations and cash flows for the periods presented in conformity with accounting principles generally accepted in the United States.

Remediation Plan for the Material Weakness

Our management is actively engaged in the planning for, and implementation of, remediation efforts to address the material weakness identified. Specifically, our management is in the process of implementing a control related to reviewing the configuration of the basis price differential calculations, including a control activity to verify any subsequent changes are appropriately reviewed and that the interface control is designed to validate the data at an appropriately disaggregated level. Our management believes that these actions will remediate the material weakness in internal control over financial reporting described in Management's Report on Internal Control Over Financial Reporting appearing under Item 8 of Part II of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2016, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is set forth in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 9B. *Other Information*

Not applicable.

PART III

ITEM 10. ***Directors, Executive Officers and Corporate Governance***

The names of executive officers and certain other senior officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2017 (the 2017 Proxy Statement).

ITEM 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the 2017 Proxy Statement.

ITEM 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information called for by this Item 12 is incorporated herein by reference to the 2017 Proxy Statement.

ITEM 13. ***Certain Relationships and Related Transactions and Director Independence***

The information called for by this Item 13 is incorporated herein by reference to the 2017 Proxy Statement.

ITEM 14. ***Principal Accountant Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the 2017 Proxy Statement.

PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules***

(a) The following financial statements, financial statement schedules and exhibits are filed as a part of this report:

1. *Financial Statements*. Chesapeake's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. No financial statement schedules are applicable or required.
3. *Exhibits*. The exhibits listed below in the Index of Exhibits (following the signatures page) are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION

Date: March 3, 2017

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

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Robert D. Lawler and Domenic J. Dell'Osso, Jr., and each of them, either one of whom may act without joinder of the other, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ ROBERT D. LAWLER **Robert D. Lawler**	President and Chief Executive Officer (Principal Executive Officer)	March 3, 2017
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 3, 2017
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President – Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 3, 2017
/s/ R. BRAD MARTIN **R. Brad Martin**	Chairman of the Board	March 3, 2017
/s/ ARCHIE W. DUNHAM **Archie W. Dunham**	Director and Chairman Emeritus	March 3, 2017
/s/ GLORIA R. BOYLAND **Gloria R. Boyland**	Director	March 3, 2017
/s/ LUKE R. CORBETT **Luke R. Corbett**	Director	March 3, 2017
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	March 3, 2017
/s/ THOMAS L. RYAN **Thomas L. Ryan**	Director	March 3, 2017

INDEX OF EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference: Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
2.1.1*	Purchase and Sale Agreement by and between Chesapeake Appalachia, L.L.C. and Southwestern Energy Production Company dated October 14, 2014.	10-K	001-13726	2.1.1	2/27/2015	
2.1.2*	Amendment to Purchase and Sale Agreement by and between Chesapeake Appalachia, L.L.C. and SWN Production Company, LLC (formerly Southwestern Energy Production Company) dated December 22, 2014.	10-K	001-13726	2.1.2	2/27/2015	
2.1.3	Settlement Agreement by and between Chesapeake Appalachia, L.L.C. and SWN Production Company, LLC (formerly Southwestern Energy Production Company) dated December 22, 2014.	10-K	001-13726	2.1.3	2/27/2015	
3.1.1	Chesapeake's Restated Certificate of Incorporation.	10-Q	001-13726	3.1.1	8/6/2014	
3.1.2	Certificate of Amendment to Restated Certificate of Incorporation.	8-K	001-13726	3.1.2	5/20/2016	
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008	
3.1.4	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008	
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010	
3.1.6	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010	
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/19/2014	
4.1**	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.12.1	11/15/2005	
4.2**	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% Senior Notes due 2017.	8-K	001-13726	4.1	12/6/2006	

4.3**	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.5% Contingent Convertible Senior Notes due 2037.	8-K	001-13726	4.1	5/15/2007
4.4**	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	5/29/2008
4.5**	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% Contingent Convertible Senior Notes due 2038.	8-K	001-13726	4.2	5/29/2008
4.6.1**	Indenture dated as of August 2, 2010 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	333-168509	4.1	8/3/2010
4.6.2	First Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010
4.6.3	Second Supplemental Indenture, dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010
4.6.4	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010 with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011
4.6.5	Fourteenth Supplemental Indenture dated March 18, 2013 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated as of August 2, 2010.	S-3	333-168509	4.17	3/18/2013
4.6.6	Sixteenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 5.375% Senior Notes due 2021.	8-A	001-13726	4.3	4/8/2013
4.6.7	Seventeenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 5.75% Senior Notes due 2023.	8-A	001-13726	4.4	4/8/2013
4.7.1**	Indenture dated as of April 24, 2014 by and among Chesapeake, as Issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee.	8-K	001-13726	4.1	4/29/2014
4.7.2	First Supplemental Indenture dated as of April 24, 2014 to Indenture dated as of April 24, 2014 with respect to Floating Rate Senior Notes due 2019.	8-K	001-13726	4.2	4/29/2014

4.7.3	Second Supplemental Indenture dated as of April 24, 2014 to Indenture dated as of April 24 2014 with respect to 4.875% Senior Notes due 2022.	8-K	001-13726	4.3	4/29/2014
4.8	Indenture dated as of December 23, 2015 among Chesapeake, as Issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee and Collateral Trustee with respect to 8.00% Senior Secured Second Lien Notes due 2022.	8-K	001-13726	4.1	12/23/2015
4.9.1	Credit Agreement dated December 15, 2014 by and among: Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; Wells Fargo Bank and National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; Bank of America, N.A., Crédit Agricole Corporate and Investment Bank and JPMorgan Chase Bank, N.A., as co-documentation agents and letter of credit issuers; and certain other lenders named therein.	10-Q	001-13726	4.1	8/14/2016
4.9.2	First Amendment to Credit Agreement dated September 30, 2015 among Chesapeake, as borrower, MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; Wells Fargo Bank, National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	10-Q	001-13726	4.1	11/4/2015
4.9.3	Second Amendment to Credit Agreement dated December 15, 2015 among Chesapeake, as borrower, MUFG Union Bank N.A., as administrative agent, co-syndication agent, a swingline lender and a letter of credit issuer; Wells Fargo Bank, National Association, as co-syndication agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	8-K	001-13726	10.1	12/16/2015
4.9.4††	Third Amendment to Credit Agreement dated April 8, 2016 among Chesapeake Energy Corporation, as borrower; MUFG Union Bank N.A., as administrative agent, a swingline lender and a letter of credit issuer; and certain other lenders named therein.	10-Q	001-13726	4.2	8/4/2016
4.10	Intercreditor Agreement dated as of December 23, 2015 between MUFG Bank, N.A., as Priority Lien Agent, and Deutsche Bank Trust Company Americas, as Second Lien Collateral Trustee, and acknowledged by Chesapeake and certain of its subsidiaries.	8-K	001-13726	10.1	12/23/2015
4.11	Collateral Trust Agreement, dated as of December 23, 2015, by and among Chesapeake, the guarantors named therein, and Deutsche Bank Trust Company Americas as the representative of the holders of the Second Lien Notes and as collateral trustee.	8-K	001-13726	10.2	12/23/2015

4.12	Term Loan Agreement dated August 23, 2016 among Chesapeake Energy Corporation, the lenders party thereto and Deutsche Bank Trust Company Americas, as term agent.	8-K	001-13726	4.1	8/24/2016
4.13	Class A Term Loan Supplement dated August 23, 2016 among Chesapeake Energy Corporation, the lenders party thereto and Deutsche Bank Trust Company Americas, as term agent.	8-K	001-13726	4.2	8/24/2016
4.14	Indenture dated as of October 5, 2016, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Deutsche Bank Trust Company Americas, as trustee, with respect to the 5.5% Convertible Senior Notes due 2026.	8-K	001-13726	10.1	8/24/2016
4.15	Collateral Trust Agreement, dated as of August 23, 2016 by and among MUFG Union Bank, N.A., as collateral trustee and revolver agent, and Deutsche Bank Trust Company Americas, as term loan agent, and acknowledged and agreed by Chesapeake Energy Corporation and certain of its subsidiaries.	8-K	001-13726	4.1	10/5/2016
4.16	Sixth Supplemental indenture dated as of December 20, 2016 to indenture dated as of April 24, 2014 with respect to 8.00% Senior Notes due 2025.	8-K	001-13726	4.2	12/20/2016
4.17	Registration Rights Agreement dated as of December 20, 2016, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Deutsche Bank Securities, Inc.	8-K	001-13726	4.4	12/20/2016
10.1.1†	Chesapeake's 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/9/2009
10.1.2†	Form of 2013 Restricted Stock Award Agreement for Chesapeake's 2003 Stock Incentive Plan.	10-K	001-13726	10.1.3	3/1/2013
10.2.1†	Chesapeake's 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	6/20/2013
10.2.2†	Form of 2013 Restricted Stock Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.3	2/4/2013
10.2.3†	Form of Nonqualified Stock Option Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	2/4/2013
10.2.4†	Form of Retention Nonqualified Stock Option Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.2	2/4/2013
10.2.5†	Form of 2013 Non-Employee Director Restricted Stock Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.13.7	3/1/2013
10.2.6†	Form of 2013 Performance Share Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.13.9	3/1/2013
10.2.7†	Form of 2014 Performance Share Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.4.7	2/27/2014

10.2.8†	Form of Restricted Stock Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-Q	001-13726	10.8	8/6/2013	
10.2.9†	Form of Non-Employee Director Restricted Stock Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-Q	001-13726	10.9	8/6/2013	
10.2.10†	Form of Pension and Equity Makeup Restricted Stock Award Agreement for 2005 Amended and Restated Long Term Incentive Plan for Robert D. Lawler.	10-Q	001-13726	10.10	8/6/2013	
10.3.1†	Chesapeake Energy Corporation Deferred Amended and Restated Deferred Compensation Plan, effective January 1, 2016.	10-K	001-13726	10.3	2/25/2016	
10.3.2†	Amendment to the Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors, effective January 1, 2017.					X
10.4†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.	10-K	001-13726	10.16	3/1/2013	
10.5†	Employment Agreement dated as of May 20, 2013 between Robert D. Lawler and Chesapeake Energy Corporation.	8-K	001-13726	10.1	5/23/2013	
10.6†	Employment Agreement dated as of January 1, 2016 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.	8-K	001-13726	10.1	1/6/2016	
10.7†	Employment Agreement dated as of January 1, 2016 between James R. Webb and Chesapeake Energy Corporation.	8-K	001-13726	10.2	1/6/2016	
10.8†	Employment Agreement dated as of January 1, 2016 between M. Christopher Doyle and Chesapeake Energy Corporation.	8-K	001-13726	10.3	1/6/2016	
10.9†	Employment Agreement dated as of January 1, 2016 between Mikell Jason Pigott and Chesapeake Energy Corporation.	8-K	001-13726	10.4	1/6/2016	
10.10†	Employment Agreement dated as of May 21, 2015 between Frank Patterson and Chesapeake Energy Corporation.	10-Q	001-13726	10.1	8/5/2015	
10.11†	Form of Employment Agreement dated as of January 1, 2016 between Executive Vice President/Senior Vice President and Chesapeake Energy Corporation.	8-K	001-13726	10.5	1/6/2016	
10.12†	Form of Indemnity Agreement for officers and directors of Chesapeake Energy Corporation and its subsidiaries.	8-K	001-13726	10.3	6/27/2012	
10.13†	Chesapeake Energy Corporation 2013 Annual Incentive Plan.	DEF 14A	001-13726	Exhibit G	5/3/2013	
10.13.1†	Chesapeake Energy Corporation 2014 Long Term Incentive Plan.	DEF 14A	001-13726	Exhibit F	4/30/2014	
10.13.2†	Form of Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.2	8/6/2014	

10.13.3†	Form of Restricted Stock Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.3	8/6/2014	
10.13.4†	Form of Nonqualified Stock Option Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.4	8/6/2014	
10.13.5†	Form of Performance Share Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.5	8/6/2014	
10.13.6†	Form of Director Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.6	8/6/2014	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
21	Subsidiaries of Chesapeake Energy Corporation.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Software Integrated Solutions, Division of Schlumberger Technology Corporation.					X
31.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
99	Report of Software Integrated Solutions, Division of Schlumberger Technology Corporation.					X
101 INS	XBRL Instance Document.					X
101 SCH	XBRL Taxonomy Extension Schema Document.					X
101 CAL	XBRL Taxonomy Extension Calculation Linkbase Document.					X
101 DEF	XBRL Taxonomy Extension Definition Linkbase Document.					X
101 LAB	XBRL Taxonomy Extension Labels Linkbase Document.					X
101 PRE	XBRL Taxonomy Extension Presentation Linkbase Document.					X

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* The Company agrees to furnish supplementally a copy of omitted exhibits and schedules to the Securities and Exchange Commission upon request.

** The Company agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

† Management contract or compensatory plan or arrangement.

†† Confidential treatment has been requested for portions of this exhibit. These portions have been omitted and submitted separately to the Securities and Exchange Commission.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this Annual Report on Form 10-K. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about Chesapeake Energy Corporation or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in our public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about Chesapeake Energy Corporation or its business or operations on the date hereof.

Company Information

BOARD OF DIRECTORS

R. Brad Martin (1,2,3,4)
Chairman of the Board

Chairman
RBM Venture Company

Former Chairman and
Chief Executive Officer
Saks Incorporated

Archie W. Dunham (1,4)
Chairman Emeritus

Former Chairman
ConocoPhillips

Gloria R. Boyland (3)
Corporate Vice President
of Operations and
Service Support
FedEx Corporation

Luke R. Corbett (1,3)
Manager
Corbett Management LLC

Former Chairman and
Chief Executive Officer
Kerr-McGee Corporation

Robert D. Lawler
President and
Chief Executive Officer
Chesapeake Energy
Corporation

Merrill A. "Pete" Miller, Jr. (2,4)
Executive Chairman
NOW Inc.

Former Executive Chairman
and Chief Executive Officer
National Oilwell Varco, Inc.

Thomas L. Ryan (2,3)
Chairman and
Chief Executive Officer
Service Corporation International

(1) Nominating, Governance and Social Responsibility Committee
(2) Finance Committee
(3) Audit Committee
(4) Compensation Committee

MANAGEMENT TEAM

Robert D. Lawler
President, Chief Executive
Officer and Director

Domenic J. "Nick" Dell'Osso, Jr.
Executive Vice President
and Chief Financial Officer

Frank J. Patterson
Executive Vice President –
Exploration and Production

M. Jason Pigott
Executive Vice President –
Operations and
Technical Services

James R. Webb
Executive Vice President –
General Counsel and
Corporate Secretary

Michael A. Johnson
Senior Vice President –
Accounting, Controller
and Chief Accounting Officer

Cathy L. Tompkins
Senior Vice President –
Information Technology and
Chief Information Officer

INVESTOR INFORMATION

Company financial information, public disclosures and other information are available through Chesapeake's website at www.chk.com. We will promptly deliver free of charge, upon request, a copy of the annual report on Form 10-K to any shareholder requesting a copy. Requests should be directed to Investor Relations at our corporate headquarters address.

COMMON STOCK

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange (NYSE) under the symbol CHK. As of March 20, 2017, the record date for our 2017 Annual Meeting of Shareholders, there were approximately 356,000 beneficial owners of our common stock.

INDEPENDENT PUBLIC ACCOUNTANTS

PricewaterhouseCoopers LLP
211 North Robinson Avenue, Suite 1400
Oklahoma City, OK 73102
(405) 290-7200

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to our transfer agent:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021
(800) 884-4225
www.computershare.com

TRUSTEE FOR THE COMPANY'S SENIOR NOTES

Issued prior to 2013
The Bank of New York
Mellon Trust Company, N.A.
101 Barclay Street, 8th Floor
New York, NY 10286
www.bnymellon.com

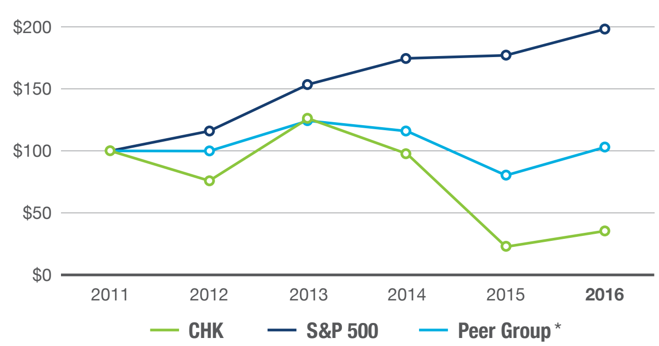
Issued in 2013 – 2016
Deutsche Bank Trust
Company Americas
60 Wall Street, 37th Floor
New York, NY 10005
www.tss.db.com

FORWARD-LOOKING STATEMENTS

The letter to shareholders includes "forward-looking statements" related to our business strategy and objectives for future operations. Although we believe there is a reasonable basis for these forward-looking statements, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2016 Annual Report on Form 10-K included in this report. We caution you not to place undue reliance on forward-looking statements, and we undertake no obligation to update this information, except as required by law. We urge you to carefully review and consider the disclosures made in our Form 10-K and our other filings with the Securities and Exchange Commission regarding the risks and factors that may affect our business.

CHESAPEAKE'S FIVE-YEAR COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on December 31, 2011 and the reinvestment of all dividends. Source: Zacks Investment Research, Inc.



* Peer Group: Anadarko Petroleum Corporation, Apache Corporation, ConocoPhillips, Devon Energy Corporation, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc. and Occidental Petroleum Corporation

CHESAPEAKE ENERGY

6100 NORTH WESTERN AVENUE
OKLAHOMA CITY, OK 73118
CHK.COM

CHESAPEAKE