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, 2017
[ ] 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
2.25% 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, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2017, was approximately $4.5 billion. As of February 15, 2018, there were 909,242,558 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2018 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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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 of natural gas.

Bcfe. Billion cubic feet of natural gas equivalent.

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. 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. Despite holding this ratio constant at six mcf to one bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil, natural gas or natural gas liquids, 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.

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. The full cost method of accounting, as governed by SEC Regulation S-X 4-10(c), consists of capitalizing all costs associated with property acquisition, exploration and development activities into a full cost pool. The full cost pool is tested for impairment quarterly using the “ceiling test” described in Regulation S-X 4-10(c). 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.

GAAP. Generally Accepted Accounting Principles in the United States.

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). 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 of Estimated Future Net Revenues or PV-10 (non-GAAP). When used with respect to oil, natural gas and NGL reserves, present value of estimated future net revenues, 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 (unless such costs are subject to change pursuant to contractual provisions), 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. As used in this report, proved reserves has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which states in part 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.

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 major expenditure is required. 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.

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 notional production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period notional production revenues, and (iii) gains and losses related to de-designated cash flow hedges originally designated to settle against current period notional production revenues. Unrealized gains and losses include the change in fair value of open derivatives scheduled to settle against future period notional 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.

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

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 formations.

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

SEC. The United States Securities and Exchange Commission.

Standardized Measure. The discounted future net cash flows relating to proved reserves based on the means of 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). The standardized measure differs from the PV-10 measure only because the former includes the effects of estimated future income tax expenses.

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.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). Forward-looking statements include our current expectations or forecasts of future events. In this context, forward-looking statements often address our expected future business and financial performance and financial condition, and often contain words such as "expect," “could,” “may,” "anticipate," "intend," "plan," “ability,” "believe," "seek," "see," "will," "would," “estimate,” “forecast,” "target," “guidance,” “outlook,” “opportunity” or “strategy.”

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

- the volatility of oil, natural gas and NGL prices;
- uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- our ability to replace reserves and sustain production;
- drilling and operating risks and resulting liabilities;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- the limitations our level of indebtedness may have on our financial flexibility;
- our inability to access the capital markets on favorable terms;
- the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- effects of environmental protection laws and regulation on our business;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- effects of acquisitions and dispositions; and
- other factors that are described under *Risk Factors* in Item 1A of this Form 10-K.

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

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.

Our Business

We are an independent exploration and production company engaged in the acquisition, exploration and development of properties for the production of oil, natural gas and NGLs from underground reservoirs. We own a large and geographically diverse portfolio of onshore U.S. unconventional natural gas and liquids assets, including interests in approximately 17,300 oil and natural gas wells. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas, the Anadarko Basin in northwestern Oklahoma and the stacked pay in the Powder River Basin in Wyoming. Our natural gas resource plays are the Marcellus Shale in the northern Appalachian Basin in Pennsylvania, the Haynesville/Bossier Shales in northwestern Louisiana and East Texas and the Utica Shale in Ohio.

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

Our strategy is to create shareholder value through the development of our significant resource plays. Our substantial inventory of hydrocarbon resources, including our undeveloped acreage position in each of our key basins, provides a strong foundation to create future value. Concentrated blocks of undeveloped acreage give us the opportunity to apply what we believe are best in class well spacing analysis, completion techniques and lateral lengths to maximize capital efficiency. We have greatly improved our capital and operating efficiency metrics over the last several years and today have what we believe is a leading cost structure in each of our major resource plays. We believe our cost structure provides a significant competitive advantage in the current commodity price environment and it is our strategy to continue to seek capital and operating efficiencies to grow this advantage.

We continue to focus on reducing debt, increasing cash provided by operating activities, and improving margins through financial discipline and operating efficiencies. To accomplish these goals, we intend to allocate our capital expenditures to projects we believe offer the highest return, deploy leading drilling and completion technology throughout our portfolio, and divest additional assets to strengthen our cost structure and our portfolio. Increasing our margins means not only increasing our absolute level of cash flow from operations, but also increasing our cash flow from operations generated per barrel of oil equivalent production. Our capital program is focused on investments that can improve our cash flow generating ability regardless of the commodity price environment. Although we expect our forecasted capital expenditures in 2018 to be lower compared to 2017, we anticipate modest production growth from both our oil-producing and natural gas-producing assets, adjusted for asset sales. Our ability to reduce capital expenditures while still growing production is primarily the result of improved operating efficiencies, including improved well performance. We continue to seek opportunities to reduce cash costs (production, general and administrative, gathering, processing and transportation and interest expenses) and improve our production volumes from existing wells.

We believe that our dedication to financial discipline, the flexibility and efficiency of our capital program and cost structure and our continued focus on safety and environmental stewardship will provide opportunities to create value for us and our shareholders.

Operating Areas

We focus our exploration, development, acquisition and production efforts in the six geographic operating areas described below.

Marcellus - Northern Appalachian Basin in Pennsylvania.

Haynesville - Northwestern Louisiana and East Texas (Gulf Coast).

Eagle Ford - South Texas.

Utica - Southern Appalachian Basin in Ohio.

Mid-Continent - Anadarko Basin in northwestern Oklahoma.

Powder River Basin - Stacked pay in Wyoming.

Well Data

As of December 31, 2017, we held an interest in approximately 17,300 gross (7,200 net) productive wells, including 14,000 properties in which we held a working interest and 3,300 properties in which we held an overriding or royalty interest. Of the wells in which we had a working interest, 9,400 gross (5,000 net) were classified as natural gas productive wells and 4,600 gross (2,200 net) were classified as oil productive wells. We operated approximately 9,500 of our 14,000 productive wells in which we had a working interest. During 2017, we drilled or participated in 401 gross (292 net) wells as operator and participated in another 67 gross (4 net) wells completed by other operators. We operate approximately 97% 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:

	2017				2016				2015			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	462	99	292	99	431	99	236	99	806	99	423	100
Dry	4	1	2	1	1	1	1	1	1	1	—	—
Total	466	100	294	100	432	100	237	100	807	100	423	100
Exploratory:												
Productive	2	100	2	100	3	100	2	100	7	100	5	100
Dry	—	—	—	—	—	—	—	—	—	—	—	—
Total	2	100	2	100	3	100	2	100	7	100	5	100

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

	2017		2016		2015	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Marcellus	43	21	19	9	44	22
Haynesville	37	34	41	34	68	49
Eagle Ford	180	106	199	116	244	138
Utica	69	56	34	17	178	114
Mid-Continent	114	58	135	62	212	63
Powder River Basin	25	21	1	1	41	34
Other	—	—	6	—	27	8
Total	468	296	435	239	814	428

As of December 31, 2017, we had 255 gross (148 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 net production volumes, average sales price received for our production, our average sales price of our production combined with our realized gains or losses from derivatives and gathering, processing and transportation expenses for the periods indicated:

	Years Ended December 31,		
	2017	2016	2015
Net Production:			
Oil (mmbbl)	33	33	42
Natural gas (bcf)	878	1,049	1,070
NGL (mmbbl)	21	24	28
Oil equivalent (mmboe)	200	233	248
Average Sales Price of Production:			
Oil ($ per bbl)	$ 51.03	$ 40.65	$ 45.77
Natural gas ($ per mcf)	$ 2.76	$ 2.05	$ 2.31
NGL ($ per bbl)	$ 23.18	$ 14.76	$ 14.06
Oil equivalent ($ per boe)	$ 22.88	$ 16.63	$ 19.23
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 53.19	$ 43.58	$ 66.91
Natural gas ($ per mcf)	$ 2.75	$ 2.20	$ 2.72
NGL ($ per bbl)	$ 22.98	$ 14.43	$ 14.06
Oil equivalent ($ per boe)	$ 23.17	$ 17.66	$ 24.54
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 2.81	$ 3.05	$ 4.22
Oil, natural gas and NGL gathering, processing and transportation	$ 7.36	$ 7.98	$ 8.55

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2017, with respect to our estimated proved reserves, the associated estimated future net revenue, the present value of estimated future net revenue ("PV-10") and the standardized measure of discounted future net cash flows ("standardized measure"). Neither the estimated future net revenue, PV-10 nor the 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, 2017			
	Oil (mmbbl)	Natural Gas (bcf)	NGL (mmbbl)	Total (mmboe)
Proved developed	151	4,980	135	1,116
Proved undeveloped	109	3,620	84	796
Total proved[a]	260	8,600	219	1,912

	Proved Developed	Proved Undeveloped	Total Proved
	($ in millions)		
Estimated future net revenue[b]	$ 9,637	$ 4,754	$ 14,391
Present value of estimated future net revenue (PV-10)[b]	$ 5,757	$ 1,733	$ 7,490
Standardized measure[b]			$ 7,490

(a) Utica, Marcellus, Haynesville and Eagle Ford accounted for approximately 25%, 24%, 21% and 19%, respectively, of our estimated proved reserves by volume as of December 31, 2017.

(b) Estimated future net revenue represents the estimated future 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, 2017. 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, 2017. The prices used in our PV-10 measure were $51.34 of oil and $2.98 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, 2017. 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 typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense. However, as we estimate no future income tax expense, the two measures are the same as of December 31, 2017.

Management uses PV-10, which is calculated without deducting estimated future income tax expenses, 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 may be 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. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

As of December 31, 2017, our proved reserve estimates included 796 mmboe of reserves classified as proved undeveloped, compared to 519 mmboe as of December 31, 2016. Presented below is a summary of changes in our proved undeveloped reserves (PUDs) for 2017:

	Total
	(mmboe)
Proved undeveloped reserves, beginning of period	519
Extensions and discoveries	604
Revisions of previous estimates	(202)
Developed	(125)
Sale of reserves-in-place	—
Purchase of reserves-in-place	—
Proved undeveloped reserves, end of period	796

As of December 31, 2017, all PUDs were planned to be developed within a five-year period. In 2017, we invested approximately $793 million to convert 125 mmboe of PUDs to proved developed reserves. In 2018, we estimate that we will invest approximately $880 million for PUD conversion. Our proved undeveloped extensions and discoveries increased by 604 mmboe of reserves as a result of longer planned lateral lengths and additional allocated capital in our five-year development plan. We recorded a downward revision of 203 mmboe from previous estimates due to an updated development plan in the Eagle Ford aligning up-spacing and our activity schedule. Additionally, PUDs were removed from properties in the Mid-Continent in the process of being divested. In addition, approximately 1 mmboe of PUDs were added due to higher commodity prices.

The future net revenue attributable to our estimated PUDs was $4.8 billion and the present value was $1.7 billion as of December 31, 2017. These were calculated assuming that we will expend approximately $4.3 billion to develop these reserves ($880 million in 2018, $1.0 billion in 2019, $1.1 billion in 2020, $858 million in 2021 and $462 million in 2022). 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. Our 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 35% in 2018, 23% in 2019, 18% in 2020, 15% in 2021 and 13% in 2022. Of our 1.116 bboe of proved developed reserves as of December 31, 2017, approximately 89 mmboe, or 8%, were non-producing.

Our 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.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2017, 2016 and 2015, 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 represents 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

Our Corporate Reserves Department prepared approximately 17% by volume, and approximately 12% by value, of our estimated proved reserves disclosed in this report. Those estimates were based upon the best available production, engineering and geologic data.

Our Director – Corporate Reserves, is the technical person primarily responsible for overseeing the preparation of our reserve estimates and for coordinating any reserves work conducted by a third-party engineering firm. Her qualifications include the following:

- Over 15 years of practical experience in the oil and gas industry, with 11 years in reservoir engineering;
- Bachelor of Science degree in Geology and Environmental Sciences;
- Master’s Degree in Petroleum and Natural Gas Engineering;
- Executive MBA; 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 significant 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 our proved reserves at the close of each quarter.
- Each quarter, Reservoir Managers, the Director – Corporate Reserves, the Vice Presidents of our business units, the Vice President 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 operations.
- The five-year PUD development plan is reviewed and approved annually by the Director of Corporate Reserves and the Vice President of Corporate and Strategic Planning.

We engaged Software Integrated Solutions, Division of Schlumberger Technology Corporation, a third-party engineering firm, to prepare approximately 83% by volume, and approximately 88% by value, of our estimated proved reserves as of December 31, 2017. A copy of the report issued by the engineering firm is filed with this report as Exhibit 99.1. The qualifications of the technical person at the firm primarily responsible for overseeing the preparation of our 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,		
	2017	2016	2015
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ 23	$ 403	$ —
Unproved properties	271	403	454
Exploratory costs	21	52	112
Development costs	2,146	1,312	2,941
Costs incurred[(a)(b)]	$ 2,461	$ 2,170	$ 3,507

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

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

Capitalized interest	$ 194	$ 242	$ 410
Asset retirement obligations[(c)]	$ (34)	$ (57)	$ (15)

(c) Includes revisions as a result of lower plugging and abandonment costs in certain of our operating areas.

A summary of our exploration and development, acquisition and divestiture activities in 2017 by operating area 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)					
Marcellus	43	21	$ 124	$ 17	$ 4	$ (13)	$ (57)	$ 75
Haynesville	37	34	411	23	(3)	(674)	(241)	(484)
Eagle Ford	180	106	754	2	—	—	—	756
Utica	69	56	375	95	1	(91)	(9)	371
Mid-Continent	114	58	281	103	20	(88)	(156)	160
Powder River Basin	25	21	220	26	—	(5)	—	241
Other	—	—	2	5	1	—	(38)	(30)
Total	468	296	$ 2,167	$ 271	$ 23	$ (871)	$ (501)	$ 1,089

(a) Includes asset retirement disposal of $66 million related to divestitures.

(b) Includes capitalized internal costs of $136 million and capitalized interest of $194 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, 2017. "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)							
Marcellus	538	346	383	215	17	16	938	577
Haynesville	401	309	158	47	11	2	570	358
Eagle Ford	313	176	129	69	—	—	442	245
Utica	315	248	1,102	686	4	4	1,421	938
Mid-Continent	1,815	847	396	158	227	39	2,438	1,044
Powder River Basin	57	45	325	229	14	1	396	275
Other[(a)]	220	145	1,470	992	662	399	2,352	1,536
Total	3,659	2,116	3,963	2,396	935	461	8,557	4,973

(a) Includes 1.6 million gross (1.3 million net) acres retained in the 2016 fourth quarter divestiture of our Devonian Shale assets, in which we retained all rights below the base of the Kope formation.

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, 2017:

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2018	485	189
2019	259	145
2020	188	142
After 2020	155	112
Held-by-production[(a)]	2,876	1,808
Total	3,963	2,396

(a) Held-by-production acres will remain in force as production continues on the subject leases.

Marketing, Gathering and Compression

Previously, we have presented two reportable operating segments: (i) exploration and production and (ii) marketing, gathering and compression. In the fourth quarter of 2017, we completed the realignment of our marketing, gathering and compression operations to serve as an ancillary service integral to our exploration and production activities. Our marketing, gathering and compression operations now principally operate to provide oil, natural gas and NGL marketing services, including commodity price structuring, securing and negotiating of gathering, hauling, processing and transportation services, contract administration and nomination services for us and other interest owners in Chesapeake-operated wells. The marketing, gathering, and compression operations also provide other services for our exploration and production activities, including services to enhance the value of oil and natural gas production by aggregating volumes 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 satisfaction of our pipeline delivery commitments.

Following this realignment, we have a single, company-wide management team that administers all activities as a whole rather than through discrete operating units, with an emphasis on allocating capital focused on the expansion of our exploration and production assets. As a result, we have concluded that we have only one reportable operating segment, which is exploration and production. Prior year financial information for our previous Marketing, Gathering and Compression reportable segment has been eliminated. See further discussion in Note 1 of the notes to our consolidated financial statements included in Item 8 of Part II of this report.

Generally, our oil production is 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. Under the terms of our percentage-of-proceeds contracts, we receive a percentage of the resale price received from the ultimate purchaser. Under our percentage-of-index contracts, the price we receive is tied to published indices.

We have entered into long-term gathering, processing, and transportation contracts with various parties that require us to deliver fixed, determinable quantities of production over specified periods of time. Certain of our contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments.

Sales to Royal Dutch Shell PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the year ended December 31, 2017. Sales to BP PLC constituted approximately 10% and 14% of our total revenues (before the effects of hedging) for the years ended December 31, 2016 and 2015, respectively.

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 us. 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, combined with our exploration, land, drilling and production capabilities and the experience of our management team, enables 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, state and local governments, the courts and federal agencies, such as the U.S. Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission, the Department of Transportation, the Department of Interior 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 resource 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' resource 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 regulated by state and federal 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 Bureau of Land Management 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 have continued to assess the impacts of hydraulic fracturing, which 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. For example, the Oklahoma Corporation Commission (OCC) has released guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to 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.*

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.

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 we are in material compliance with these laws and regulations. We do not believe 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 currently 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. We recycle and reuse 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 United States. 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 release of hydrocarbons. 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 a prescribed 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. In recent years, the EPA has considered additional standards of performance to limit methane emissions from oil and gas sources. In 2017, the EPA announced that it is reconsidering these standards and has proposed to stay their requirements. However, the standards currently remain in effect. 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, state governments and/or regional agencies are considering 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. In August of 2017, the United States informed the United Nations of its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 2020. 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 that may 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, we 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.

We maintain a control of well insurance 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. We also carry a $250 million comprehensive general liability umbrella insurance policy. In addition, we maintain a $100 million pollution liability insurance 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 our 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

We own an office complex in Oklahoma City and we own or lease 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, 51, 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., 41, has served as Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso served as our Vice President – Finance and Chief Financial Officer of our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., from August 2008 to November 2010.

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

Frank Patterson, 59, 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.

M. Jason Pigott, *Executive Vice President – Operations and Technical Services*

M. Jason Pigott, 44, 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, 50, 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.

William M. Buergler – Senior Vice President and Chief Accounting Officer

William Buergler, 45, has served as Senior Vice President and Chief Accounting Officer since August 2017. Previously, he served as Vice President - Tax since July 2014. Before joining Chesapeake, he worked for Ernst & Young LLP, where he served as a Partner since 2009.

Other Senior Officer

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

Cathlyn L. Tompkins, 57, 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

We had approximately 3,200 employees as of December 31, 2017. Subsequent to December 31, 2017, we underwent a reduction in workforce that affected approximately 13% of our employees across all functions, primarily at our Oklahoma City campus.

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 incur 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, debt service 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 oil and natural gas prices, such as those experienced in 2015 and continuing into the first quarter of 2017, may result in ceiling test write-downs of our oil and natural gas properties.

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 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, natural gas, liquefied natural gas and NGL;
- 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. As of February 22, 2018, including January and February derivative contracts that have settled, approximately 74% and 68% of our forecasted 2018 oil production and natural gas production, respectively, was hedged through swaps and collars. Even with oil, natural gas and NGL derivatives currently in place to mitigate price risks associated with a portion of our 2018 cash flows, we have substantial exposure to oil, natural gas and NGL prices in 2019 and beyond. In addition, a prolonged extension of lower prices could reduce the quantities of reserves that we may economically produce.

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, 2017, we had approximately $10.0 billion in principal amount of debt outstanding (including $52 million of current maturities and $781 million drawn under our senior secured revolving credit facility). We had approximately $116 million of letters of credit issued and borrowing capacity of approximately $2.9 billion under our $3.8 billion senior secured revolving credit facility.

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 the cyclical nature of our business, economic downturns or other adverse developments in our business;
- could limit our ability to access capital markets, refinance our existing indebtedness, raise capital on favorable terms, or obtain additional financing for working capital, capital expenditures, acquisitions, debt service requirements, 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 those that have less restrictive terms governing their indebtedness, thereby enabling competitors to take advantage of opportunities that our indebtedness may prevent 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 drawn on our credit facility for liquidity, and the borrowing base under our credit facility is subject to redetermination on June 15, 2018. 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. 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, some or all of which may not be available to us 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 could 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 the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Low commodity prices have caused and may continue to cause lenders to increase interest rates, enact tighter lending standards, 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 have a material adverse effect on 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.

Our earnings and cash flow could 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 have a material adverse impact on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

If we do not generate sufficient cash flow from operations to service our outstanding indebtedness, or if future borrowings are not available to us in an amount sufficient to enable us to pay or refinance our indebtedness, we may be required to undertake various alternative financing plans, which may include:

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

We cannot assure you that we would be able to implement any of the above alternative financing plans, if necessary, on commercially reasonable terms or at all. 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 amounts 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.

Borrowings under our revolving 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 hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same.

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. Declines in oil, NGL and natural gas prices, or a prolonged period of low oil, NGL and natural gas prices and other events, some of which are beyond our control, 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 that, if not cured or waived, could result in acceleration of all indebtedness outstanding thereunder and cross-default rights under our other debt. 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 amounts owed to the lenders or to our other debt holders.

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

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. These collateral requirements depend, in part, on our credit ratings. As of February 20, 2018, we have received requests and posted approximately $151 million of collateral related to certain of our marketing and other contracts. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $486 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. Any downgrade to our credit ratings could impact the posting of collateral consisting of cash or letters of credit, which would reduce availability under our credit facility, and 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 present value of future net revenues of our proved reserves, 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 could be material. As of December 31, 2017, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $7.5 billion, which exceeds the carrying value of our oil and natural gas properties.

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, 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, 2017 reflect an expected decline in the production rate on our producing properties of approximately 35% in 2018 and 23% in 2019. 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, 2017, approximately 42% 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 $4.3 billion during the next five years ending in 2022. 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 our 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, 2017 present value is based on a $51.34 per bbl of oil price and a $2.98 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 future net cash flows from our proved reserves and their present value. Any changes in demand for oil and natural gas, governmental regulations or taxation will also affect the future net cash flows from our production. In addition, the 10% discount factor that 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 commercially productive reservoirs will not 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 under the full cost method, 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 properties are subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are renewed.

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 benefit we would receive from increases in commodity prices, may 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, we enter into oil, natural gas and NGL price derivative contracts. Our oil, natural gas and NGL derivative arrangements may limit the benefit we would receive from increases in commodity prices. The fair value of our oil, natural gas and NGL derivative instruments can fluctuate significantly between periods. Our decision to mitigate cash flow volatility through derivative arrangements, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to enter into derivatives if the pricing environment for certain time periods is not deemed to be favorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities to monetize gain positions for the purpose of funding our capital program.

Most of our oil, natural gas and NGL derivative contracts are with counterparties under bi-lateral hedging arrangements. Under a majority of our arrangements, the collateral provided for our obligations is secured by the same hydrocarbon interests that secure our senior secured revolving credit facility. Under other arrangements, 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. Our counterparties' obligations under the arrangements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us exceed defined thresholds. Collateral requirements are dependent to a large extent on oil and natural gas prices.

Oil, natural gas and NGL 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, 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 cash flows being exposed to commodity price changes.

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, entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sales of natural gas and NGL and similar theories. Numerous cases 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 and possible antitrust violations. 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 2018 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, 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 our 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 have adopted or 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 have also been certain governmental reviews 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. Based on the results 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. In addition, a number of lawsuits have been filed in Oklahoma alleging damage from earthquakes relating to disposal well operations.

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. Additional regulation could also lead to greater opposition to hydraulic fracturing, including litigation.

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, hydraulic fracturing 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 OCC’s 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 us, causing increased costs and reduced demand for oil and natural gas.

Various state governments and regional organizations are considering 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 a prescribed 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. In August 2017, the United States informed the United Nations of its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 2020. 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 changes in tax law could increase our cost of doing business.

We are subject to taxation by various taxing authorities at the federal, state and local levels where we do business. New legislation increasing our tax burden could be enacted by any of these governmental authorities. Recently, legislative changes imposing additional taxes or increases to existing taxes were considered in Louisiana, Ohio, Oklahoma, Pennsylvania and Wyoming. It is possible that any of these states could enact new tax legislation making it more costly for us to explore for oil and natural gas resources.

Additionally, on December 22, 2017, the President of the United States signed into law tax reform legislation informally known as the Tax Cuts and Jobs Act (the "Tax Act") that substantially revised numerous areas of U.S. federal income tax law. Although we do not expect there to be an immediate adverse impact on our federal income taxes from the Tax Act, new restrictions on items such as the utilization of net operating loss (NOL) carryforwards and the deductibility of business interest could adversely impact our federal income taxes in future years. Furthermore, the extent to which state and local taxing authorities will adopt tax laws that conform with or differ from provisions of the Tax Act is unclear. Any change in state or local tax law in response to the Tax Act could affect our tax burden and make it more costly for us to explore for oil and natural gas resources.

Further, our ability to utilize our federal NOL carryforwards to reduce future taxable income and federal income tax is subject to various limitations under the Internal Revenue Code of 1986, as amended (the "Code"). The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the acquisition or disposition of our stock by 5% shareholders and our offering of stock during any three-year period resulting in a cumulative shift of more than 50% in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of NOL carryforwards (accumulated prior to the change date) that can be used to offset our future taxable income. The limitation is generally equal to the product of (a) the fair market value of our equity multiplied by (b) the long-term tax-exempt rate in effect for the month in which the ownership change occurs. In addition, if we are in a net unrealized built-in gain position at the time of an ownership change then the limitation may be increased if there are recognized built-in gains during a certain recognition period following the ownership change. If we are in a net unrealized built-in loss position at the time of an ownership change then the limitation may apply to tax attributes other than just NOL carryforwards such as depreciable basis. Some states impose similar limitations on tax attribute utilization upon experiencing an ownership change. We do not believe that an ownership change has occurred as of December 31, 2017 that would limit future utilization of our NOL carryforwards or other tax attributes.

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.

Risks related to potential acquisitions or dispositions may adversely affect our business.

From time to time, we evaluate acquisitions and dispositions of assets, businesses and other investments. These transactions may not result in the anticipated benefits or efficiencies. In addition, acquisitions may be financed by borrowings, requiring us to incur more debt, or by the issuance of our common stock. Any such acquisition or disposition involves risks and we cannot assure that:

- any acquisition would be successfully integrated into our operations and internal controls;
- the due diligence conducted prior to an acquisition would uncover situations that could result in financial or legal exposure, such as title defects and potential environmental and other liabilities;

- post-closing purchase price adjustments will be realized in our favor;
- our assumptions about, among other things, reserves, estimated production, revenues, capital expenditures, operating, operating expenses and costs would be accurate;
- any investment, acquisition, disposition or integration would not divert management resources from the operation of our business; and
- any investment, acquisition, or disposition or integration would not have a material adverse effect on our financial condition, results of operations, cash flows or reserves.

If any of these risks materialize, the benefits of such acquisition or disposition may not be fully realized, if at all, and our financial condition, results of operations, cash flows and reserves could be negatively impacted.

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

Historically, 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 require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.

In certain shale plays, the capacity of gathering and transportation systems 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 and the providing or expansion of trucking services 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 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.

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 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 or to retire outstanding debt and/or preferred stock. 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. We had previously failed to pay dividends on our outstanding preferred stock with respect to four quarterly periods during the fiscal year ended December 31, 2016, before resuming payment, in arrears, in the first quarter of 2017.

Certain anti-takeover and other 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, term loan facility, preferred stock and certain of our notes 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 and to offer to repurchase such notes 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

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

Regulatory and Related Proceedings. We have received U.S. Postal Service and state subpoenas seeking information on our royalty payment practices. We have engaged in discussions with the U.S. Postal Service and state agency representatives and continue to respond to related subpoenas and demands.

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

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

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

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of our divestiture of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights, intentional interference with contractual relations, and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources. These lawsuits seek in aggregate compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. On December 20, 2017, we reached a tentative settlement to resolve substantially all Pennsylvania civil royalty cases for approximately $30 million.

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

Environmental Proceedings

Our subsidiary Chesapeake Appalachia, LLC (CALLC) is engaged in discussions with the EPA, the USACE and the Pennsylvania Department of Environmental Protection (PADEP) regarding potential violations of the permitting requirements of the federal CWA, 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.

We are also in discussions with PADEP regarding gas migration in the vicinity of certain of our wells in Bradford County, Pennsylvania. We believe we are close to identifying agreed-upon steps to resolve PADEP’s concerns regarding the issue. In addition to these steps, we anticipate making a donation of $300,000 to the PADEP’s well plugging fund.

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

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

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

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:

	Common Stock	
	High	Low
Year Ended December 31, 2017:		
Fourth Quarter	$ 4.38	$ 3.41
Third Quarter	$ 5.20	$ 3.55
Second Quarter	$ 6.59	$ 4.38
First Quarter	$ 7.32	$ 4.88
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

Shareholders

As of February 20, 2018, there were approximately 1,850 holders of record of our common stock and approximately 595,000 beneficial owners.

Dividends

We ceased paying dividends on our common stock in the 2015 third quarter and do not anticipate paying any dividends on our common stock in the foreseeable future. Our revolving credit facility, our term loan facility and the certificates of designation for our preferred stock 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. After suspending the payment of dividends on our outstanding convertible preferred stock during fiscal year 2016, we reinstated the payment of dividends on each series of our outstanding convertible preferred stock beginning with the dividends payable in the 2017 first quarter and paid all dividends in arrears.

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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, 2017:

Period	Total Number of Shares Purchased[(a)]		Average Price Paid Per Share[(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs		Maximum Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
						($ in millions)
October 1, 2017 through October 31, 2017	11,666	$	4.36	—	$	1,000
November 1, 2017 through November 30, 2017	—	$	—	—	$	1,000
December 1, 2017 through December 31, 2017	—	$	—	—	$	1,000
Total	11,666	$	4.36	—		

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

(b) In December 2014, our Board of Directors authorized the repurchase of up to $1 billion of our common stock from time to time. The repurchase program does not have an expiration date. As of December 31, 2017, there have been no repurchases 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, 2017, 2016, 2015, 2014 and 2013. The data are derived from our audited consolidated financial statements. 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,				
	2017	2016	2015	2014	2013
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA:					
Total revenues	$ 9,496	$ 7,872	$ 12,764	$ 23,125	$ 19,080
Net income (loss) available to common stockholders[(a)]	$ 813	$ (4,915)	$ (14,738)	$ 1,273	$ 474
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 0.90	$ (6.43)	$ (22.26)	$ 1.93	$ 0.73
Diluted	$ 0.90	$ (6.43)	$ (22.26)	$ 1.87	$ 0.73
CASH DIVIDEND DECLARED PER COMMON SHARE	$ —	$ —	$ 0.0875	$ 0.35	$ 0.35
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 12,425	$ 13,028	$ 17,314	$ 40,655	$ 41,663
Long-term debt, net of current maturities	$ 9,921	$ 9,938	$ 10,311	$ 11,058	$ 12,767
Total equity (deficit)	$ (372)	$ (1,203)	$ 2,397	$ 18,205	$ 18,140

(a) Includes $2.564 billion and $18.238 billion of full cost ceiling test write-downs on our oil and natural gas properties for the years ended December 31, 2016 and 2015, respectively. In 2017, 2014 and 2013, we did not have any ceiling test impairments on our oil and natural gas properties.

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

Overview

Introduction

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

Overview of 2017 Results

The transformation of Chesapeake over the past four years has been significant and our progress continued in 2017. Our progress has been guided by our strategies of financial discipline, pursuing profitable and efficient growth from our captured resources, leveraging technology and our operational expertise to unlock additional domestic resources through exploration and development and optimizing our portfolio through business development. Our strategies have not changed through the price cycles of the past several years, and we believe our recent accomplishments and achievements in 2017 have made our company stronger. Highlights include the following:

- grew estimated proved reserves volumes by 16% in 2017, net of divestitures;
- improved cash flow from operations by $949 million;
- grew production by 3%, adjusted for asset sales, and met our targeted goal of reaching 100,000 barrels of average net oil production per day in the fourth quarter of 2017, a significant accomplishment representing 11% growth from our 2016 fourth quarter oil volumes;
- improved our cost structure by reducing our production, general and administrative, and gathering, processing and transportation expenses by $510 million, or 18%;
- generated approximately $1.3 billion in net proceeds from the disposition of certain non-core assets and other property sales;
- reduced outstanding secured term debt by approximately $1.3 billion, or 32%;
- continued to reduce legal obligations;
- exchanged approximately 10.0 million shares of common stock for approximately $100 million of liquidation value of our preferred stock, eliminating approximately $6 million of annual dividend obligations; and
- achieved company record health, safety and environmental performance by lowering total recordable incident rates to 0.045 and reducing reportable spills by 15% compared to 2016.

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions)				
Net income (loss) available to common stockholders	$ 813	n/m	$ (4,915)	67 %	$ (14,738)
Net earnings (loss) per diluted common share	$ 0.90	n/m	$ (6.43)	71 %	$ (22.26)
Adjusted production[a] (mboe per day)	541	3 %	525	3 %	511
Total production (mboe per day)	548	(14)%	635	(6)%	679
Average sales price (per boe)	$ 22.88	38 %	$ 16.63	(14)%	$ 19.23
Oil, natural gas and NGL production expenses	$ 562	(21)%	$ 710	(32)%	$ 1,046
Oil, natural gas and NGL gathering, processing and transportation expenses	$ 1,471	(21)%	$ 1,855	(12)%	$ 2,119
General and administrative expenses	$ 262	9 %	$ 240	2 %	$ 235
Total debt (principal amount)	$ 9,981	— %	$ 9,989	3 %	$ 9,706
Estimated proved reserves (mmboe)	1,912	12 %	1,708	14 %	1,504

(a) Adjusted for assets sold.

Business and Industry Outlook

Over the past decade, the landscape of energy production has changed dramatically in the United States. Domestic energy production capabilities have increased the nation's supply of both crude oil and natural gas, primarily driven by advances in technology, horizontal drilling and hydraulic fracture stimulation techniques. As a result of this increase in domestic supply of crude oil and natural gas, commodity prices for these products are meaningfully lower than they were a decade ago, but may remain volatile for the foreseeable future. To this end, we will always strive to protect a portion of our projected cash flow through our commodity hedging program as we see appropriate.

As of February 22, 2018, including January and February derivative contracts that are settled, approximately 74% of our projected full year 2018 crude oil production was hedged through swaps and open collars at an average of $52.41 per barrel and approximately 68% of our projected full year 2018 natural gas production was hedged through swaps and collars at an average of $3.10 per mcf. Our crude oil hedges are below current 2018 NYMEX crude oil strip prices of approximately $60.00 per barrel, and our natural gas hedges currently sit in a profitable position, above current 2018 NYMEX natural gas strip prices of approximately $2.80 per mcf. While we cannot predict the future movements of commodity prices with complete accuracy, we believe it is prudent to protect a portion of our projected cash flow through hedging and plan to continue to do so in the future.

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

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

With regard to our debt, we are committed to decreasing the amount of debt outstanding. To accomplish this objective, we intend to allocate our capital expenditures to the highest-return projects, deploy leading drilling and completion technology throughout our portfolio to profitably and efficiently grow, and divest additional large assets to strengthen our cost structure and our portfolio. Increasing our margins means not only increasing our level of cash flow from operations, but also increasing our cash flow from operations generated per barrel of equivalent production. We are seeking to reduce cash costs (production, general and administrative and gathering, processing and transportation expenses), improve our production volumes from existing wells, and achieve additional operating and capital efficiencies with a focus on growing our oil volumes. Finally, we seek to maintain our high level of health, safety, and environmental performance and stewardship.

We have already made significant progress towards achieving our strategic priorities to date in 2018. So far we have:

- signed agreements for the sale of properties in the Mid-Continent, including our Mississippian Lime assets, for an expected aggregate amount of approximately $500 million in proceeds that we expect to close by the end of the 2018 second quarter; and
- received net proceeds of approximately $74 million from the sale of approximately 4.3 million shares of FTS International, Inc. (NYSE: FTSI). After the sale, we own approximately 22 million shares of FTSI.

The proceeds from these divestitures will be used to repay debt and fund our development program, based on market conditions.

Over the last four years, we have fundamentally transformed substantially all aspects of our business, removing financial and operational complexity, significantly improving our balance sheet and addressing numerous legacy issues. Our 2018 capital expenditures program, while planned to be approximately 12% lower than our 2017 program, is expected to generate greater capital efficiency as we focus on expanding our margins by investing in the highest-return projects. In January, we reduced our workforce by approximately 13% as part of an overall plan to reduce costs and better align our workforce to the needs of our business. We are committed to reducing our debt and improving cash flow from operations, and believe we can make material advances in both of these areas in 2018.

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, and will continue to have, affected the amount of cash we generate and have available for capital expenditures and debt service and has had a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we can economically produce. Other risks and uncertainties that could affect our liquidity include, but are not limited to, counterparty credit risk for our receivables, access to capital markets, regulatory risks, our ability to meet financial ratios and covenants in our financing agreements and the availability of lenders' commitments as a result of regulatory pressures in the lending market.

As of December 31, 2017, we had a cash balance of $5 million compared to $882 million as of December 31, 2016, and we had a net working capital deficit of $831 million as of December 31, 2017, compared to a net working capital deficit of $1.506 billion as of December 31, 2016. As of December 31, 2017, we had total principal debt of $9.981 billion, compared to $9.989 billion as of December 31, 2016. As of December 31, 2017, we had $2.888 billion of borrowing capacity available under our senior secured revolving credit facility, with outstanding borrowings of $781 million and $116 million utilized for various letters of credit. Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures, meet our debt service requirements and fund our other commitments and obligations for the next 12 months. See Note 3 of the notes to our 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.

Even though we have taken measures to mitigate the liquidity concerns facing us for the next 12 months, as outlined above in *Overview of 2017 Results* and *Business and Industry Outlook*, there can be no assurance that these measures will be sufficient for periods beyond the next 12 months. If needed, we may seek to access the capital markets or otherwise refinance a portion of our outstanding indebtedness to improve our liquidity. We closely monitor the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our revolving credit facility. Furthermore, our ability to generate operating cash flow in the current commodity price environment, sell assets, access capital markets or take any other action to improve our liquidity and manage our debt is subject to the risks discussed above and the other risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

Capital Expenditures

We have significant control and flexibility over the timing and execution of our development plan, enabling us to reduce our capital spending as needed. Our forecasted 2018 capital expenditures, inclusive of capitalized interest, are $2.0 – $2.4 billion compared to our 2017 capital spending level of $2.5 billion. Management continues to review operational plans for 2018 and beyond, which could result in changes to projected capital expenditures and projected revenues from sales of oil, natural gas and NGL.

We may continue to use a combination of cash, borrowings and issuances of our common stock or other securities to retire our outstanding debt and/or preferred stock through privately negotiated transactions, open market repurchases, redemptions, tender offers or otherwise, but we are under no obligation to do so.

Derivative and Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Our oil, natural gas and NGL derivative activities, when combined with our sales of oil, natural gas and NGLs, allow us to predict with greater certainty the total revenue we will receive.

We utilize various oil, natural gas and NGL derivative instruments to protect a portion of our cash flow against downside risk. As of February 22, 2018, we have downside price protection in 2018 and 2019 through the following oil, natural gas and NGL derivative instruments:

Oil Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	% of Forecasted Production (if applicable)	Average NYMEX Price
		(mbbls)		
2018	Swaps	21,710	68%	$52.87
2018	Three-way collars	1,825	6%	$39.15/$47.00/$55.00
2018	Calls	1,840	6%	$52.87
2018	Basis protection swaps	10,769	34%	$3.32
2019	Swaps	3,273	Not disclosed	$56.04

Natural Gas Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	% of Forecasted Production (if applicable)	Average NYMEX Price
		(mmcf)		
2018	Swaps	531,613	63%	$3.11
2018	Two-way collars	47,450	6%	$3.00/$3.25
2018	Calls	65,700	8%	$6.27
2018	Basis protection swaps	64,589	8%	($0.52)

NGL Derivatives[(a)]

Year	Type of Derivative Instrument	Notional Volume	% of Forecasted Production (if applicable)	Average NYMEX Price
		(mmgal)		
2018	Butane swaps	5	1%	$0.88
2018	Butane % of WTI swaps	5	1%	70.5% of WTI
2018	Propane swaps	15	2%	$0.73
2018	Ethane swaps	8	1%	$0.28

(a) Includes amounts settled in January and February 2018.

See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of derivatives and hedging activities.

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to contractual obligations and off-balance sheet commitments. The table below summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2017:

	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]	$ 9,981	$ 53	$ 1,825	$ 3,915	$ 4,188
Interest	3,774	653	1,258	924	939
Operating lease obligations[b]	14	6	7	1	—
Operating commitments[c]	9,190	1,102	2,030	1,654	4,404
Unrecognized tax benefits[d]	101	—	4	97	—
Standby letters of credit	116	116	—	—	—
Other	22	4	8	8	2
Total contractual cash obligations[e]	$ 23,198	$ 1,934	$ 5,132	$ 6,599	$ 9,533

(a) See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our long-term debt.

(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 an analysis 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 19, 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 in Note 12 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 expose us to credit risk from our counterparties. To mitigate this risk, we enter into oil, natural gas and NGL derivative contracts only with counterparties that we deem to have acceptable credit strength and are deemed by management to be competent and competitive market-makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2017, our oil, natural gas and NGL derivative instruments were spread among 11 counterparties. Additionally, the counterparties under these arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($959 million as of December 31, 2017) and exploration and production companies that own interests in properties we operate ($209 million as of December 31, 2017). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2017, 2016 and 2015, we recognized $9 million, $10 million and $4 million, respectively, of bad debt expense related to potentially uncollectible receivables.

Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, processing, transportation and hedging agreements. As of February 20, 2018, we have received requests and posted approximately $151 million of collateral related to certain of our marketing and other contracts. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $486 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business relationships with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business arrangements and by offsetting amounts that the counterparty owes us. Any posting of collateral consisting of cash or letters of credit reduces availability under our revolving credit facility and negatively impacts our liquidity.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the years ended December 31, 2017, 2016 and 2015. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of divestitures of oil and natural gas assets.

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Cash provided by (used in) operating activities	$ 745	$ (204)	$ 1,234
Proceeds from credit facility borrowings, net	781	—	—
Proceeds from issuance of a term loan, net	—	1,476	—
Proceeds from issuances of senior notes, net	1,585	2,210	—
Proceeds from divestitures of proved and unproved properties, net	1,249	1,406	189
Proceeds from sales of other property and equipment, net	55	131	89
Other	—	—	52
Total sources of cash and cash equivalents	$ 4,415	$ 5,019	$ 1,564

Cash Flow from Operating Activities

Cash provided by operating activities was $745 million in 2017 compared to cash used in operating activities of $204 million in 2016 and cash provided by operating activities of $1.234 billion in 2015. The increase in 2017 is primarily the result of higher prices for the oil, natural gas and NGL we sold and decreases in certain of our operating expenses, partially offset by lower volumes of oil, natural gas and NGL sold, the payment related to the litigation involving the early redemption of our 6.775% Senior Notes due 2019 and payments for terminations of transportation contracts. The decrease from 2015 is primarily the result of lower prices for the oil and natural gas we sold, lower volumes of oil, natural gas and NGL sold, less gain from our commodity derivatives, 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, certain impairments, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See further discussion below under *Results of Operations*.

Revolving Credit Facility

We have a senior secured revolving credit facility currently subject to a $3.8 billion borrowing base that matures in December 2019. As of December 31, 2017, we had $2.888 billion of borrowing capacity available under our revolving credit facility. Our next borrowing base redetermination is scheduled for the second quarter of 2018. As of December 31, 2017, we had outstanding borrowings of $781 million under the revolving credit facility and had used $116 million of the revolving credit facility for various letters of credit. Borrowings under the facility bear interest at a variable rate. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the terms of the revolving credit facility. As of December 31, 2017, we were in compliance with all applicable financial covenants under the credit agreement. Our first lien secured leverage ratio was approximately 0.52 to 1.00, our interest coverage ratio was approximately 2.51 to 1.00 and our debt to capitalization ratio was approximately 0.38 to 1.00.

We currently plan to use cash flow from operations to fund our capital expenditures for 2018. We expect to generate additional liquidity with proceeds from future sales of assets that do not fit our strategic priorities. Under our revolving credit facility, we borrowed $7.771 billion and repaid $6.990 billion in 2017, we borrowed and repaid $5.146 billion in 2016 and we had no borrowings or repayments in 2015.

Debt issuances

The following table reflects the proceeds received from issuances of debt in 2017, 2016 and 2015. 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,					
	2017		2016		2015	
	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	1,600	1,585	1,000	975	—	—
Term loans	—	—	1,500	1,476	—	—
Total	$ 1,600	$ 1,585	$ 3,750	$ 3,686	$ —	$ —

Divestitures of Proved and Unproved Properties

During 2017, we divested certain non-core assets for approximately $1.249 billion. Proceeds from these transactions were used to repay debt and fund our development program. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Oil and Natural Gas Expenditures:			
Drilling and completion costs	$ 2,186	$ 1,295	$ 3,095
Acquisitions of proved and unproved properties	101	552	123
Interest capitalized on unproved leasehold	184	236	410
Total oil and natural gas expenditures	2,471	2,083	3,628
Other Uses of Cash and Cash Equivalents:			
Cash paid to repurchase debt	2,592	2,734	508
Cash paid for title defects	—	69	—
Cash paid to repurchase noncontrolling interest	—	—	143
Additions to other property and equipment	21	37	143
Dividends paid	183	—	289
Distributions to noncontrolling interest owners	8	10	85
Other	17	29	51
Total other uses of cash and cash equivalents	2,821	2,879	1,219
Total uses of cash and cash equivalents	$ 5,292	$ 4,962	$ 4,847

Oil and Natural Gas Expenditures

Our drilling and completion costs increased in 2017 compared to 2016 primarily as a result of increased drilling and completion activity as well as higher service and supply costs. During 2017, our average operated rig count was 17 rigs compared to an average operated rig count of ten rigs in 2016 and we completed 401 operated wells in 2017 compared to 382 in 2016. Our acquisitions of proved and unproved properties were higher in 2016 compared to 2017 and 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.

Repurchase of Debt

In 2017, we used $2.592 billion of cash to repurchase $2.389 billion principal amount of debt. In 2016, we used $2.734 billion of cash to repurchase $2.884 billion principal amount of debt. In 2015, we used $508 million of cash to repurchase $513 million principal amount of debt.

Dividends

We paid dividends of $183 million on our preferred stock during 2017, including $92 million of dividends in arrears that had been suspended throughout 2016. We did not pay dividends on our preferred stock in 2016 and paid $171 million of preferred stock dividends in 2015. We paid dividends of $118 million on our common stock in 2015. We eliminated common stock dividends in the 2015 third quarter and do not anticipate paying any common stock dividends in the foreseeable future.

Results of Operations

Oil, Natural Gas and NGL Production and Average Sales Prices

	2017								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	810	2.44	—	—	135	25	14.65
Haynesville	—	—	785	2.85	—	—	131	24	17.12
Eagle Ford	58	52.34	142	3.30	18	22.95	100	18	39.24
Utica	10	46.04	427	3.00	26	23.06	107	19	21.80
Mid-Continent	16	49.66	163	2.78	10	22.89	53	10	27.55
Powder River Basin	6	49.97	37	3.01	3	27.33	15	3	32.58
Retained assets	90	51.04	2,364	2.76	57	23.20	541	99	22.97
Divested assets	—	46.25	42	2.63	—	13.36	7	1	16.24
Total	90	51.03	2,406	2.76	57	23.18	548	100%	22.88

	2016								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	759	1.59	—	—	126	20	9.56
Haynesville	—	—	681	2.31	—	—	114	18	13.87
Eagle Ford	56	42.19	140	2.61	17	14.85	97	15	30.97
Utica	13	34.17	480	2.34	32	14.44	125	20	16.17
Mid-Continent	13	41.60	163	2.21	8	16.87	48	8	21.48
Powder River Basin	6	39.58	37	2.36	3	17.27	15	2	24.78
Retained assets	88	40.78	2,260	2.09	60	15.01	525	83	17.54
Divested assets	3	36.62	607	1.92	7	12.41	110	17	12.26
Total	91	40.65	2,867	2.05	67	14.76	635	100%	16.63

	2015								
	Oil		Natural Gas		NGL		Total		
	mbbl per day	$/bbl	mmcf per day	$/mcf	mbbl per day	$/bbl	mboe per day	%	$/boe
Marcellus	—	—	739	1.89	—	—	123	18	11.32
Haynesville	—	—	524	2.66	—	—	88	13	15.97
Eagle Ford	65	47.01	148	2.73	16	14.13	106	16	34.70
Utica	13	36.82	423	2.35	33	14.93	116	17	16.92
Mid-Continent	16	47.37	199	2.60	10	15.08	59	9	24.14
Powder River Basin	9	43.34	49	2.77	3	14.09	20	3	28.15
Retained assets	103	45.44	2,082	2.32	62	14.70	512	76	20.35
Divested assets	11	48.78	849	2.26	15	11.38	167	24	15.77
Total	114	45.77	2,931	2.31	77	14.06	679	100%	19.23

Natural gas and NGL production decreased primarily as a result of the sale of certain of our Barnett, Mid-Continent and Devonian assets in 2016 and the sale of certain of our Haynesville assets in 2017.

Oil, Natural Gas and NGL Sales

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions)				
Oil	$ 1,668	23%	$ 1,351	(29)%	$ 1,904
Natural gas	2,422	12%	2,155	(13)%	2,470
NGL	484	34%	360	(8)%	393
Oil, natural gas and NGL sales	$ 4,574	18%	$ 3,866	(19)%	$ 4,767

2017 vs. 2016. The increase in the price received per boe in 2017 resulted in a $1.25 billion increase in revenues, and decreased sales volumes resulted in a $542 million decrease in revenues, for a total net increase in revenues of $708 million.

2016 vs. 2015. The decrease in the price received per boe in 2016 resulted in a $606 million decrease in revenues, and decreased sales volumes resulted in a $295 million decrease in revenues, for a total net decrease in revenues of $901 million.

Oil, Natural Gas and NGL Derivatives

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions)				
Oil derivatives – realized gains (losses)	$ 70	(28)%	$ 97	(89)%	$ 880
Oil derivatives – unrealized gains (losses)	(134)	58 %	(318)	41 %	(536)
Total gains (losses) on oil derivatives	(64)		(221)		344
Natural gas derivatives – realized gains (losses)	(9)	n/m	151	(65)%	437
Natural gas derivatives – unrealized gains (losses)	489	n/m	(500)	n/m	(157)
Total gains (losses) on natural gas derivatives	480		(349)		280
NGL derivatives – realized gains (losses)	(4)	50 %	(8)	— %	—
NGL derivatives – unrealized gains (losses)	(1)	— %	—	— %	—
Total gains (losses) on NGL derivatives	(5)		(8)		—
Total gains (losses) on oil, natural gas and NGL derivatives	$ 411		$ (578)		$ 624

See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for a complete discussion of our derivative activity.

A change in oil, natural gas and NGL prices has a significant impact on our revenues and cash flows. Assuming our 2017 production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would have resulted in an increase or decrease in 2017 revenues and cash flows from operations of approximately $33 million and $31 million, respectively, an increase or decrease of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in 2017 revenues and cash flows from operations of approximately $88 million and $87 million, respectively, and an increase or decrease of $1.00 per barrel of NGL sold would have resulted in an increase or decrease in 2017 revenues and cash flows from operations of approximately $21 million and $20 million, respectively.

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

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions)				
Marketing, gathering and compression revenues	$ 4,511	(2)%	$ 4,584	(38)%	$ 7,373
Marketing, gathering and compression expenses	4,598	(4)%	4,778	(33)%	7,130
Marketing, gathering and compression gross margin	$ (87)	55 %	$ (194)	180 %	$ 243

2017 vs. 2016. Gross margin increased primarily as a result of the reversal of cumulative unrealized gains associated with the termination of a supply contract derivative in 2016 as well as the sale of a significant portion of our gathering and compression assets in 2016.

2016 vs. 2015. Gross margin decreased primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations. Additionally, the 2015 amount included unrealized gains of $296 million on the fair value of our supply contract derivative.

Oil, Natural Gas and NGL Production Expenses

	Years Ended December 31,				
	2017	change	2016	change	2015
Oil, natural gas and NGL production expenses			($ in millions)		
Marcellus	$ 20	11 %	$ 18	(18)%	$ 22
Haynesville	53	36 %	39	(24)%	51
Eagle Ford	187	28 %	146	(19)%	181
Utica	37	(16)%	44	(24)%	58
Mid-Continent	180	15 %	157	(29)%	221
Powder River Basin	27	35 %	20	(35)%	31
Retained Assets[(a)]	504	19 %	424	(25)%	564
Divested Assets	14	(94)%	243	(42)%	422
Total	518	(22)%	667	(32)%	986
Ad valorem tax[(b)]	44	2 %	43	(28)%	60
Total oil, natural gas and NGL production expenses	$ 562	(21)%	$ 710	(32)%	$ 1,046
Oil, natural gas and NGL production expenses			($ per boe)		
Marcellus	$ 0.41	5 %	$ 0.39	(20)%	$ 0.49
Haynesville	$ 1.10	17 %	$ 0.94	(41)%	$ 1.59
Eagle Ford	$ 5.12	24 %	$ 4.13	(12)%	$ 4.71
Utica	$ 0.94	(2)%	$ 0.96	(29)%	$ 1.36
Mid-Continent	$ 9.39	6 %	$ 8.87	(14)%	$ 10.31
Powder River Basin	$ 4.90	35 %	$ 3.64	(15)%	$ 4.27
Retained Assets[(a)]	$ 2.55	15 %	$ 2.21	(27)%	$ 3.02
Divested Assets	$ 5.44	(10)%	$ 6.02	(13)%	$ 6.90
Total	$ 2.59	(10)%	$ 2.87	(28)%	$ 3.98
Ad valorem tax[(b)]	$ 0.23	5 %	$ 0.22	(31)%	$ 0.32
Total oil, natural gas and NGL production expenses per boe	$ 2.81	(8)%	$ 3.05	(28)%	$ 4.22

(a) Includes assets retained as of December 31, 2017.

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

2017 vs. 2016. The absolute and per unit decrease was the result of the sale of certain oil and natural gas properties in 2016, partially offset by increased workover costs in the Eagle Ford and increased water disposal costs in the Eagle Ford and Mid-Continent. Production expenses in 2017 and 2016 included approximately $19 million and $44 million associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our remaining VPP agreement decrease and operating efficiencies generally improve.

2016 vs. 2015. The absolute and per unit decrease was the result of a reduction in repairs and maintenance expense as well as operating efficiencies across most of our operating areas.

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

	Years Ended December 31,		
	2017	2016	2015
	($ in millions, except per unit)		
Oil, natural gas and NGL gathering, processing and transportation expenses	$ 1,471	$ 1,855	$ 2,119
Oil ($ per bbl)	$ 3.94	$ 3.61	$ 3.38
Natural gas ($ per mcf)	$ 1.34	$ 1.47	$ 1.66
NGL ($ per bbl)	$ 7.88	$ 7.83	$ 7.37
Total ($ per boe)	$ 7.36	$ 7.98	$ 8.55

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

2016 vs. 2015. The absolute decrease was primarily due to lower volumes. The per unit decrease was primarily due to contract improvements and asset sales.

Production Taxes

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions, except per unit)				
Production taxes	$ 89	20%	$ 74	(25)%	$ 99
Production taxes per boe	$ 0.44	38%	$ 0.32	(20)%	$ 0.40

2017 vs. 2016. The absolute and per unit increase in production taxes was primarily due to higher prices received for our oil, natural gas and NGL production, offset by lower production volumes.

2016 vs. 2015. The absolute and per unit decrease in production taxes was primarily due to lower production volumes and lower prices received for our oil, natural gas and NGL production.

General and Administrative Expenses

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions, except per unit)				
Gross overhead	$ 791	(12)%	$ 900	(18)%	$ 1,102
Allocated to production expenses	(177)	(15)%	(209)	(16)%	(248)
Allocated to marketing, gathering and compression expenses	(29)	(47)%	(55)	(32)%	(81)
Capitalized	(137)	(8)%	(149)	(23)%	(193)
Reimbursed from third parties	(186)	(25)%	(247)	(28)%	(345)
General and administrative expenses, net	$ 262	9 %	$ 240	2 %	$ 235
General and administrative expenses, net per boe	$ 1.31	27 %	$ 1.03	8 %	$ 0.95

2017 vs. 2016. Gross overhead decreased primarily due to lower compensation costs and lower legal fees. The absolute and per unit net expense increase was primarily due to less overhead allocated to production expenses, marketing, gathering, and compression expenses and capitalized general and administrative costs, as well as less overhead billed to third party working interest owners, due to certain divestitures in 2016 and 2017.

2016 vs. 2015. Gross overhead decreased primarily due to lower compensation costs. The absolute and per unit increase was primarily due to less overhead allocated to production expenses, marketing, gathering, and compression expenses and capitalized general and administrative costs, as well as less overhead billed to third party working interest owners, due to certain divestitures in 2016.

Restructuring and Other Termination Costs. We recorded expenses of $6 million and $36 million in 2016 and 2015, respectively. See Note 15 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our restructuring and termination costs.

Provision for Legal Contingencies, Net

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions)				
Provision for legal contingencies, net	$ (38)	(131)%	$ 123	(65)%	$ 353

2017 vs. 2016. The 2017 amount consists of the recovery of a legal settlement, partially offset by accruals for loss contingencies primarily related to royalty claims. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of royalty claims.

2016 vs. 2015. The decrease was primarily the result of the resolution of litigation we were defending against the state of Michigan and $339 million related to litigation involving the early redemption of our 6.775% Senior Notes due 2019.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions, except per unit)				
Oil, natural gas and NGL depreciation, depletion and amortization	$ 913	(9)%	$ 1,003	(52)%	$ 2,099
Oil, natural gas and NGL depreciation, depletion and amortization per boe	$ 4.56	6 %	$ 4.31	(49)%	$ 8.47

2017 vs. 2016. The absolute decrease was primarily the result of the sale of certain of our Barnett and Mid-Continent assets in 2016 and the sale of certain of our Haynesville assets in 2017.

2016 vs. 2015. The absolute and per unit decrease was primarily the result of a lower amortization base, which is due to the 2016 and 2015 impairments of our oil and natural gas properties.

Depreciation and Amortization of Other Assets

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions, except per unit)				
Depreciation and amortization of other assets	$ 82	(21)%	$ 104	(20)%	$ 130
Depreciation and amortization of other assets per boe	$ 0.41	(9)%	$ 0.45	(15)%	$ 0.53

The absolute and per unit decrease for each year was primarily the result of the sale of other assets. See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of other assets.

Impairment of Oil and Natural Gas Properties

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions)				
Impairment of oil and natural gas properties	$ —	(100)%	$ 2,564	(86)%	$ 18,238

In 2017, we did not have an impairment for our oil and natural gas properties. In 2016 and 2015, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment in the carrying value of our oil and natural gas properties of $2.564 billion and $18.238 billion, respectively. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairments.

Impairments of Fixed Assets and Other

	Years Ended December 31,				
	2017	change	2016	change	2015
	($ in millions)				
Impairment of fixed assets and other	$ 421	(50)%	$ 838	332%	$ 194

The amounts consist of costs incurred to terminate various gathering and transportation agreements, including those associated with oil and gas asset divestitures, as well as impairments of building and other fixed assets. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairments and other expense.

Interest Expense

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Interest expense on senior notes	$ 551	$ 588	$ 682
Interest expense on term loan	127	46	—
Amortization of loan discount, issuance costs and other	40	33	62
Amortization of premium	(138)	(165)	(3)
Interest expense on revolving credit facility	39	35	12
Realized gains on interest rate derivatives[a]	(3)	(11)	(6)
Unrealized (gains) losses on interest rate derivatives[b]	4	21	(6)
Capitalized interest	(194)	(251)	(424)
Total interest expense	$ 426	$ 296	$ 317
Average senior notes borrowings	$ 7,714	$ 8,749	$ 11,705
Average credit facilities borrowings	$ 443	$ 195	$ —
Average term loan borrowings	$ 1,446	$ 537	$ —

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

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

The 2017 increase in interest expense is primarily due to an increase in term loan interest expense and a decrease in capitalized interest as a result of lower average balances of unproved oil and natural gas properties, the primary asset on which interest is capitalized. The overall increase in interest expense is offset in part by a decrease in interest expense on senior notes due to the decrease in the average outstanding principal amount of senior notes. The 2016 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 $2.11 per boe in 2017 compared to $1.18 per boe in 2016 and $1.30 per boe in 2015.

Impairment of Investments. In 2016 and 2015, we recognized impairments of investments of $119 million and $53 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 FTSI International, Inc. (FTSI) investment due to the extended decrease in the oil and natural gas pricing environment.

Gains (Losses) on Purchases or Exchanges of Debt. In 2017, we retired $2.389 billion principal amount of our outstanding senior notes, senior secured second lien notes and contingent convertible notes through purchases in the open market, tender offers, redemptions or repayment upon maturity for $2.592 billion, which included the maturity of our 6.25% Euro-denominated Senior Notes due 2017 and the corresponding cross currency swap. We recorded an aggregate gain of approximately $233 million associated with the repurchases and tender offers.

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

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, with no interest expense 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 of $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 this repurchase.

Income Tax Expense (Benefit). We recorded income tax expense of $2 million in 2017, and income tax benefits of $190 million and $4.463 billion in 2016 and 2015, respectively. Our effective income tax rate was 0.2% in 2017 compared to 4.1% in 2016 and 23.4% in 2015. The decrease in the effective income tax rate from 2016 to 2017 is primarily due to the intraperiod tax allocation provisions under GAAP applicable to 2016 which are not applicable in 2017. 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).

Critical Accounting Policies and Estimates

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

Impairment of 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. We follow 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 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.

We review the carrying value of our oil and natural gas properties under the full cost method of accounting prescribed by the SEC 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.

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.

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

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

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, our financial condition and results of operations may be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2017 and 2016, the fair values of our derivatives were net liabilities of $35 million and net liabilities of $577 million, respectively.

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

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

Our judgments and assumptions in estimating future taxable income include such factors as future operating conditions and commodity prices when determining if deferred tax assets are not more-likely-than-not to be realized. As of December 31, 2017 and 2016, we had deferred tax assets totaling $2.826 billion and $4.690 billion upon which we had a valuation allowance of $2.674 billion and $4.389 billion, respectively.

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

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

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

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

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

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

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our commodity hedging arrangements that require counterparties to post collateral if their obligations to us are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 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, 2017, our oil, natural gas and NGL derivative instruments consisted of the following types of instruments:

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

As of December 31, 2017, we had the following open oil, natural gas and NGL derivative instruments:

	Volume	Weighted Average Price				Fair Value
		Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps:						
Short-term	20	$ 51.99	$ —	$ —	$ —	$ (147)
Long-term	1	$ 53.60	$ —	$ —	$ —	(4)
Three Way Collars:						
Short-term	2	$ —	$ 55.00	$39.15 / $47.00	$ —	$ (10)
Call Swaptions:						
Short-term	2	$ 52.87	$ —	$ —	$ —	$ (13)
Basis Protection Swaps:						
Short-term	11	$ —	$ —	$ —	$ 3.32	(9)
Total Oil						(183)
	(bcf)	($ per mcf)				
Natural Gas:						
Swaps[(a)]:						
Short-term	532	$ 3.11	$ —	$ —	$ —	149
Collars:						
Short-term	47	$ —	$ 3.25	$ 3.00	$ —	11
Call Options (sold):						
Short-term	66	$ —	$ 6.27	$ —	$ —	(3)
Long-term	44	$ —	$ 12.00	$ —	$ —	—
Basis Protection Swaps:						
Short-term	65	$ —	$ —	$ —	$ (0.52)	(7)
Total Natural Gas						150
	(mmgal)	($ per gal)				
NGL:						
Propane Swaps						
Short-term	15	$ 0.73	$ —	$ —	$ —	(2)
Butane Swaps						
Short-term	5	$ 0.88	$ —	$ —	$ —	—
Short-term % of WTI	5	70.5%	$ —	$ —	$ —	—
Ethane Swaps						
Short-term	8	$ 0.28	$ —	$ —	$ —	—
Total NGL						(2)
			Total Estimated Fair Value			$ (35)

(a) This amount includes a sold option to enhance the swap price at an average price of $3.40/mmbtu covering 44 tbtu, included in the sold call options.

In addition to the open derivative positions disclosed above, as of December 31, 2017, we had $81 million of net derivative losses related to settled contracts for future periods that will be recorded within oil, natural gas and NGL revenues as realized gains (losses) on derivatives once they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production, based on the terms specified in the original contract as noted below:

	December 31, 2017	
	($ in millions)	
Short-term	$	(24)
Long-term		(57)
Total	$	(81)

The table below reconciles the changes in fair value of our oil and natural gas derivatives during 2017. Of the $35 million fair value liability as of December 31, 2017, a $31 million liability relates to contracts maturing in the next 12 months and a $4 million liability relates to contracts maturing after 12 months. All open derivative instruments as of December 31, 2017 are expected to mature by December 31, 2020.

	December 31, 2017	
	($ in millions)	
Fair value of contracts outstanding, as of January 1, 2017	$	(504)
Change in fair value of contracts		445
Contracts realized or otherwise settled		24
Fair value of contracts outstanding, as of December 31, 2017	$	(35)

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates, using the earliest demand repurchase date for contingent convertible senior notes. As of December 31, 2017, we had total debt of $9.981 billion, including $7.588 billion of fixed rate debt at interest rates averaging 6.95% and $2.393 billion of floating rate debt at an interest rate of 6.53%.

	Years of Maturity						
	2018	2019	2020	2021	2022	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[a]	$ 53	$ —	$ 665	$ 814	$ 1,868	$ 4,188	$ 7,588
Average interest rate	6.42%	—%	6.71%	5.88%	7.25%	7.07%	6.95%
Debt – variable rate	$ —	$ 1,160	$ —	$ 1,233	$ —	$ —	$ 2,393
Average interest rate	—%	4.10%	—%	8.81%	—%	—%	6.53%

(a) This amount excludes $9 million of premium, discount and deferred financing costs included in debt and $2 million of interest rate derivatives.

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, 2017, we had no interest rate derivatives outstanding.

As of December 31, 2017, we had $7 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains or losses once they are transferred from our senior note liability or within interest expense as unrealized gains or losses over the remaining six-year term of our related senior notes.

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

ITEM 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 Rule 13a-15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control-Integrated Framework* (2013) in conducting the required assessment of effectiveness of the Company's internal control over financial reporting.

Management has performed an assessment of the effectiveness of the Company's internal control over financial reporting and has determined the Company’s internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of the Company's internal control over financial reporting, as of December 31, 2017, 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

February 22, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Chesapeake Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes of Chesapeake Energy Corporation and its subsidiaries as listed in the accompanying index (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
February 22, 2018

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($2 and $1 attributable to our VIE)	$ 5	$ 882
Accounts receivable, net	1,322	1,057
Short-term derivative assets	27	—
Other current assets	171	203
Total Current Assets	1,525	2,142
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full cost accounting:		
Proved oil and natural gas properties ($488 and $488 attributable to our VIE)	68,858	66,451
Unproved properties	3,484	4,802
Other property and equipment	1,986	2,053
Total Property and Equipment, at Cost	74,328	73,306
Less: accumulated depreciation, depletion and amortization (($461) and ($458) attributable to our VIE)	(63,664)	(62,726)
Property and equipment held for sale, net	16	29
Total Property and Equipment, Net	10,680	10,609
LONG-TERM ASSETS:		
Other long-term assets	220	277
TOTAL ASSETS	$ 12,425	$ 13,028

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

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

	December 31, 2017	December 31, 2016
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 654	$ 672
Current maturities of long-term debt, net	52	503
Accrued interest	137	113
Short-term derivative liabilities	58	562
Other current liabilities ($3 and $3 attributable to our VIE)	1,455	1,798
Total Current Liabilities	2,356	3,648
LONG-TERM LIABILITIES:		
Long-term debt, net	9,921	9,938
Long-term derivative liabilities	4	15
Asset retirement obligations, net of current portion	162	247
Other long-term liabilities	354	383
Total Long-Term Liabilities	10,441	10,583
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 5,603,458 and 5,839,506 shares outstanding	1,671	1,771
Common stock, $0.01 par value, 2,000,000,000 and 1,500,000,000 shares authorized: 908,732,809 and 896,279,353 shares issued	9	9
Additional paid-in capital	14,437	14,486
Accumulated deficit	(16,525)	(17,474)
Accumulated other comprehensive loss	(57)	(96)
Less: treasury stock, at cost; 2,240,394 and 1,220,504 common shares	(31)	(27)
Total Chesapeake Stockholders' Equity (Deficit)	(496)	(1,331)
Noncontrolling interests	124	128
Total Equity (Deficit)	(372)	(1,203)
TOTAL LIABILITIES AND EQUITY	$ 12,425	$ 13,028

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2017	2016	2015
	($ in millions except per share data)		
REVENUES:			
Oil, natural gas and NGL	$ 4,985	$ 3,288	$ 5,391
Marketing, gathering and compression	4,511	4,584	7,373
Total Revenues	9,496	7,872	12,764
OPERATING EXPENSES:			
Oil, natural gas and NGL production	562	710	1,046
Oil, natural gas and NGL gathering, processing and transportation	1,471	1,855	2,119
Production taxes	89	74	99
Marketing, gathering and compression	4,598	4,778	7,130
General and administrative	262	240	235
Restructuring and other termination costs	—	6	36
Provision for legal contingencies, net	(38)	123	353
Oil, natural gas and NGL depreciation, depletion and amortization	913	1,003	2,099
Depreciation and amortization of other assets	82	104	130
Impairment of oil and natural gas properties	—	2,564	18,238
Impairments of fixed assets and other	421	838	194
Net (gains) losses on sales of fixed assets	(3)	(12)	4
Total Operating Expenses	8,357	12,283	31,683
INCOME (LOSS) FROM OPERATIONS	1,139	(4,411)	(18,919)
OTHER INCOME (EXPENSE):			
Interest expense	(426)	(296)	(317)
Losses on investments	—	(8)	(96)
Loss on sale of investment	—	(10)	—
Impairments of investments	—	(119)	(53)
Gains on purchases or exchanges of debt	233	236	279
Other income	9	19	8
Total Other Expense	(184)	(178)	(179)
INCOME (LOSS) BEFORE INCOME TAXES	955	(4,589)	(19,098)
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	(9)	(19)	(36)
Deferred income taxes	11	(171)	(4,427)
Total Income Tax Expense (Benefit)	2	(190)	(4,463)
NET INCOME (LOSS)	953	(4,399)	(14,635)
Net (income) loss attributable to noncontrolling interests	(4)	9	68
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	949	(4,390)	(14,567)
Preferred stock dividends	(85)	(97)	(171)
Loss on exchange of preferred stock	(41)	(428)	—
Earnings allocated to participating securities	(10)	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 813	$ (4,915)	$ (14,738)
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ 0.90	$ (6.43)	$ (22.26)
Diluted	$ 0.90	$ (6.43)	$ (22.26)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ —	$ —	$ 0.0875
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	906	764	662
Diluted	906	764	662

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,		
	2017	2016	2015
	($ in millions)		
NET INCOME (LOSS)	$ 953	$ (4,399)	$ (14,635)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Unrealized gains (losses) on derivative instruments, net of income tax expense (benefit) of $0, ($14) and $12	5	(13)	20
Reclassification of losses on settled derivative instruments, net of income tax expense of $0, $18 and $15	34	16	24
Other Comprehensive Income	39	3	44
COMPREHENSIVE INCOME (LOSS)	992	(4,396)	(14,591)
COMPREHENSIVE (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(4)	9	68
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 988	$ (4,387)	$ (14,523)

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,		
	2017	2016	2015
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ 953	$ (4,399)	$ (14,635)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	995	1,107	2,229
Deferred income tax expense (benefit)	11	(171)	(4,427)
Derivative (gains) losses, net	(409)	739	(932)
Cash receipts (payments) on derivative settlements, net	(18)	448	1,123
Stock-based compensation	49	52	78
Impairment of oil and natural gas properties	—	2,564	18,238
Net (gains) losses on sales of fixed assets	(3)	(12)	4
Renegotiation of natural gas gathering contracts	—	(115)	—
Impairments of fixed assets and other	4	467	175
Losses on investments	—	8	96
Loss on sale of investment	—	10	—
Impairments of investments	—	119	53
Gains on purchases or exchanges of debt	(235)	(236)	(304)
Restructuring and other termination costs	—	3	(14)
Provision for legal contingencies, net	(42)	87	340
Other	(89)	(114)	244
(Increase) decrease in accounts receivable and other assets	(163)	(4)	1,186
Decrease in accounts payable, accrued liabilities and other	(308)	(757)	(2,220)
Net Cash Provided By (Used In) Operating Activities	745	(204)	1,234
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(2,186)	(1,295)	(3,095)
Acquisitions of proved and unproved properties	(285)	(788)	(533)
Proceeds from divestitures of proved and unproved properties	1,249	1,406	189
Additions to other property and equipment	(21)	(37)	(143)
Proceeds from sales of other property and equipment	55	131	89
Cash paid for title defects	—	(69)	—
Additions to investments	—	—	(1)
Decrease in restricted cash	—	—	52
Other	—	(8)	(9)
Net Cash Used In Investing Activities	(1,188)	(660)	(3,451)

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

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

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from revolving credit facility borrowings	7,771	5,146	—
Payments on revolving credit facility borrowings	(6,990)	(5,146)	—
Proceeds from issuance of senior notes, net	1,585	2,210	—
Proceeds from issuance of term loan, net	—	1,476	—
Cash paid to purchase debt	(2,592)	(2,734)	(508)
Cash paid for common stock dividends	—	—	(118)
Cash paid for preferred stock dividends	(183)	—	(171)
Cash paid to repurchase noncontrolling interest of CHK C-T	—	—	(143)
Distributions to noncontrolling interest owners	(8)	(10)	(85)
Other	(17)	(21)	(41)
Net Cash Provided By (Used In) Financing Activities	(434)	921	(1,066)
Net increase (decrease) in cash and cash equivalents	(877)	57	(3,283)
Cash and cash equivalents, beginning of period	882	825	4,108
Cash and cash equivalents, end of period	$ 5	$ 882	$ 825

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

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest paid, net of capitalized interest	$ 492	$ 344	$ 235
Income taxes paid, net of refunds received	$ (16)	$ (27)	$ 44
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Change in accrued drilling and completion costs	$ 14	$ (23)	$ (148)
Change in accrued acquisitions of proved and unproved properties	$ 9	$ (13)	$ 55
Change in divested proved and unproved properties	$ (57)	$ 52	$ 35
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,		
	2017	2016	2015
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning of period	$ 1,771	$ 3,062	$ 3,062
Exchange/conversions of 236,048, 1,412,009 and 0 shares of preferred stock for common stock	(100)	(1,291)	—
Balance, end of period	1,671	1,771	3,062
COMMON STOCK:			
Balance, beginning of period	9	7	7
Exchange of senior notes, contingent convertible notes and preferred stock	—	1	—
Conversion of preferred stock	—	1	—
Balance, end of period	9	9	7
ADDITIONAL PAID-IN CAPITAL:			
Balance, beginning of period	14,486	12,403	12,531
Stock-based compensation	54	64	71
Exchange of contingent convertible notes for 0 and 55,427,782 and 0 shares of common stock	—	241	—
Exchange of senior notes for 0 and 53,923,925 and 0 shares of common stock	—	229	—
Exchange/conversion of preferred stock for 9,965,835, 120,186,195 and 0 shares of common stock	100	1,290	—
Issuance of 5.5% convertible senior notes due 2026	—	445	—
Tax effect on the issuance of 5.5% convertible senior notes due 2026	—	(165)	—
Equity component of contingent convertible notes repurchased, net of tax	(20)	(16)	—
Dividends on preferred stock	(183)	—	(128)
Dividends on common stock	—	—	(59)
Issuance costs	—	(5)	—
Increase (decrease) in tax benefit from stock-based compensation	—	—	(12)
Balance, end of period	14,437	14,486	12,403
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance, beginning of period	(17,474)	(13,084)	1,483
Net income (loss) attributable to Chesapeake	949	(4,390)	(14,567)
Balance, end of period	(16,525)	(17,474)	(13,084)
ACCUMULATED OTHER COMPREHENSIVE LOSS:			
Balance, beginning of period	(96)	(99)	(143)
Hedging activity	39	3	44
Balance, end of period	(57)	(96)	(99)

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,		
	2017	2016	2015
	($ in millions)		
TREASURY STOCK – COMMON:			
Balance, beginning of period	(27)	(33)	(37)
Purchase of 1,206,419, 37,871 and 54,493 shares for company benefit plans	(7)	—	(1)
Release of 186,529, 255,091 and 231,081 shares from company benefit plans	3	6	5
Balance, end of period	(31)	(27)	(33)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT)	(496)	(1,331)	2,256
NONCONTROLLING INTERESTS:			
Balance, beginning of period	128	141	1,302
Net income attributable to noncontrolling interests	4	(9)	(68)
Distributions to noncontrolling interest owners	(8)	(4)	(78)
Repurchase of noncontrolling interest of CHK C-T	—	—	(1,015)
Balance, end of period	124	128	141
TOTAL EQUITY (DEFICIT)	$ (372)	$ (1,203)	$ 2,397

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

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

Basis of Presentation

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

Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the related disclosures in the financial statements. Management evaluates its estimates and related assumptions regularly, including those related to the impairment of oil and natural gas properties, oil and natural gas reserves, derivatives, income taxes, collectibility of accounts receivable, impairment of other property and equipment, environmental remediation costs, asset retirement obligations, litigation and regulatory proceedings and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ significantly from these estimates.

Consolidation

We consolidate entities in which we have a controlling financial interest. We consolidate subsidiaries in which we hold, directly or indirectly, more than 50% of the voting rights and variable interest entities (VIEs) in which we are the primary beneficiary. We use the equity method of accounting to record our net interests where we have the ability to exercise significant influence through our 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. Undivided interests in oil and natural gas properties are consolidated on a proportionate basis.

Segments

Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating an enterprise’s resources and assessing its operating performance.

We have historically presented two reportable operating segments: (i) exploration and production and (ii) marketing, gathering and compression. In the fourth quarter of 2017, we completed the realignment of our marketing, gathering and compression operations to serve as an ancillary service integral to our exploration and production activities. Following this realignment, we have a single, company-wide management team that administers all activities as a whole rather than through discrete operating units, with an emphasis on allocating capital focused on the expansion of our exploration and production assets. As a result, we have concluded that we have only one reportable operating segment, which is exploration and production. Prior year financial information for our previous marketing, gathering and compression reportable operating segment has been eliminated.

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. In order to determine whether we own a variable interest in a VIE, we perform a qualitative analysis of the entity's design, organizational structure, primary decision makers and relevant agreements. We continually monitor our consolidated VIE to determine if any events have occurred that could cause the primary beneficiary to change. See Note 8 for further discussion of our VIE.

Cash and Cash Equivalents

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

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL and from exploration and production companies that own interests in properties we operate. This industry concentration could affect our overall exposure to credit risk, either positively or negatively, because our purchasers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and we generally require letters of credit or parent guarantees for receivables from parties deemed to have sub-standard credit, unless the credit risk can otherwise be mitigated. We utilize an allowance method in accounting for bad debt based on historical trends in addition to specifically identifying receivables that we believe may be uncollectible. Accounts receivable as of December 31, 2017 and 2016 are detailed below:

	December 31,	
	2017	**2016**
	($ in millions)	
Oil, natural gas and NGL sales	$ 959	$ 840
Joint interest	209	156
Other	184	93
Allowance for doubtful accounts	(30)	(32)
Total accounts receivable, net	$ 1,322	$ 1,057

Oil and Natural Gas Properties

We follow 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, 2017 were prepared by an independent engineering firm and our internal staff. 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, 2017 and the year in which the associated costs were incurred:

	Year of Acquisition				
	2017	2016	2015	Prior	Total
	($ in millions)				
Leasehold cost	$ 70	$ 89	$ 87	$ 2,368	$ 2,614
Exploration cost	50	9	33	11	103
Capitalized interest	154	116	120	377	767
Total	$ 274	$ 214	$ 240	$ 2,756	$ 3,484

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 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, 2017, 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 reserve 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 impairment 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. We review our 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.

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 significant changes to the quarterly ceiling test calculation.

Other Property and Equipment

Other property and equipment consists primarily of natural gas compressors, buildings and improvements, land, vehicles, computers and office equipment. 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. 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.

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, 2017 and 2016 are liabilities of approximately $92 million and $77 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, 2017 and 2016, totaled $22 million and $32 million, respectively, and are being amortized over the life of credit facility using the straight-line method. Included in debt are costs associated with the issuance of our senior notes and term loan. The remaining unamortized issuance costs as of December 31, 2017 and 2016, totaled $63 million and $64 million, respectively, and are being amortized over the life of the senior notes using the effective interest method.

Litigation Contingencies

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

Environmental Remediation Costs

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

Asset Retirement Obligations

We recognize liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our oil and natural gas properties. See Note 17 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, 2017 and 2016, was $5 million and $9 million, respectively.

Marketing, Gathering and Compression Sales. In connection with the marketing of our production, we take title to the oil, natural gas and NGL we purchase from other interest owners at defined delivery points and deliver the product to third parties, at which time revenues are recorded. 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, primarily for 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, our results of operations related to 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.

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 at fair value, and changes in 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.

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

We have established the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. See Note 11 for further discussion of our derivative instruments.

Share-Based Compensation

Our 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 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.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* that supersedes virtually all existing revenue recognition guidance. The new standard includes a five-step revenue recognition model that requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration we expect to be entitled in exchange for those goods. The standard is required to be adopted using either the full retrospective approach or the modified retrospective approach. We will adopt this new standard in the first quarter of 2018 using the modified retrospective approach. Among other things, the standard requires enhanced disclosures about revenue and provides guidance for transactions that were not previously addressed comprehensively. As of December 31, 2017, we have completed our evaluation of the new standard and have concluded that the cumulative effect of adoption will not have a material impact on our consolidated financial statements. The adoption will result in a change in the gross versus net presentation of certain revenue transactions in our consolidated statements of operations, but any such presentation changes would not have an impact on income (loss) from operations, earnings per share or cash flows.

In January 2016, the FASB issued amendments on certain aspects of recognition, measurement, presentation, and disclosure of financial instruments through ASU 2016-01, *Financial Instruments-Overall (Subtopic 825-10)*: Recognition and Measurement of Financial Assets and Financial Liabilities. ASU 2016-01 will require equity investments (except those accounted for under the equity method of accounting, or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. In addition, ASU 2016-01 changes certain disclosure requirements and other aspects of GAAP. We will adopt ASU 2016-01 on January 1, 2018. As of December 31, 2017, we have completed our evaluation of the new standard and have concluded that the effect on our financial statements is not material, but may be material in the future if we were to sell a portion of our equity method investments such that we no longer had the ability to exercise significant influence over the operating and financial activities of the investee.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* which updated lease accounting guidance requiring lessees to recognize most leases, including operating leases, on the balance sheet as a right of use asset and lease liability. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2018 and will be adopted using a modified retrospective transition method, which requires applying the new standard to leases that exist or are entered into after the beginning of the earliest period in the financial statements. Early adoption is permitted, but we do not plan to early adopt. The standard will not apply to our leases of mineral rights. We are continuing to evaluate the impact of this standard on our consolidated financial statements and related disclosures.

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

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2016 and 2015 to conform to the presentation used for the 2017 consolidated financial statements.

2. Earnings Per Share

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

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

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

	Years Ended December 31,		
	2017	**2016**	**2015**
		(in millions)	
Common stock equivalent of our preferred stock outstanding	60	63	113
Common stock equivalent of our convertible senior notes outstanding	146	146	—
Common stock equivalent of our preferred stock outstanding prior to exchange	1	37	—
Participating securities	1	1	1

3. Debt

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

	December 31, 2017		December 31, 2016	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
6.25% euro-denominated senior notes due 2017	$ —	$ —	$ 258	$ 258
6.5% senior notes due 2017	—	—	134	134
7.25% senior notes due 2018	44	44	64	64
Floating rate senior notes due 2019	380	380	380	380
6.625% senior notes due 2020	437	437	780	780
6.875% senior notes due 2020	227	227	279	278
6.125% senior notes due 2021	548	548	550	550
5.375% senior notes due 2021	267	267	270	270
4.875% senior notes due 2022	451	451	451	451
8.00% senior secured second lien notes due 2022[(a)]	1,416	1,895	2,419	3,409
5.75% senior notes due 2023	338	338	338	338
8.00% senior notes due 2025	1,300	1,290	1,000	985
5.5% convertible senior notes due 2026[(b)(c)(d)]	1,250	837	1,250	811
8.00% senior notes due 2027	1,300	1,298	—	—
2.75% contingent convertible senior notes due 2035[(d)]	—	—	2	2
2.5% contingent convertible senior notes due 2037[(d)]	—	—	114	112
2.25% contingent convertible senior notes due 2038[(b)(d)]	9	8	200	180
Term loan due 2021	1,233	1,233	1,500	1,500
Revolving credit facility	781	781	—	—
Debt issuance costs	—	(63)	—	(64)
Interest rate derivatives	—	2	—	3
Total debt, net	9,981	9,973	9,989	10,441
Less current maturities of long-term debt, net[(e)]	(53)	(52)	(506)	(503)
Total long-term debt, net	$ 9,928	$ 9,921	$ 9,483	$ 9,938

(a) The carrying amounts as of December 31, 2017 and 2016, include premium amounts of $479 million and $990 million, respectively, associated with a troubled debt restructuring. The premium is being amortized based on the effective yield method.

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

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

Optional Conversion by Holders. Prior to maturity under certain circumstances and at the holder's option, the notes are convertible. The notes may be converted into cash, our common stock, or a combination of cash and common stock, at our election. One triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. During the fourth quarter of 2017, the price of our common stock was below the threshold level and, as a result, the holders do not have the option to convert their notes in the first quarter of 2018 under this provision. The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision during the year ended December 31, 2017. Upon conversion of a convertible senior note, the holder will receive cash, common stock or a combination of cash and common stock, at our election, according to the conversion rate specified in the indenture.

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

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

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

(d) The carrying amounts as of December 31, 2017 and 2016, are reflected net of discounts of $414 million and $461 million, respectively, associated with the equity component of our convertible and contingent convertible senior notes. This amount is being amortized based on the effective yield method through the first demand repurchase date as applicable.

(e) As of December 31, 2017, current maturities of long-term debt, net includes our 7.25% Senior Notes due December 2018 and our 2.25% Contingent Convertible Notes due 2038 Notes.

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

	Principal Amount of Debt Securities
	($ in millions)
2018	$ 53
2019	1,161
2020	664
2021	2,048
2022	1,867
Thereafter	4,188
Total	$ 9,981

Debt Issuances and Retirements - 2017

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

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

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

Debt Issuances and Retirements - 2016

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, we 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.

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.

We retired $2.884 billion principal amount of our outstanding senior notes and contingent convertible senior notes through purchases in the open market, tender offers or repayment upon maturity for $2.734 billion. Additionally, we privately negotiated an exchange of approximately $577 million principal amount of our outstanding senior notes and contingent convertible senior notes for 109,351,707 common shares.

We recorded an aggregate 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.

Senior Secured Second Lien Notes

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

Senior Notes, Contingent Convertible Senior Notes and Convertible Senior Notes

Our senior notes and our contingent convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries. See Note 19 for consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

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

Term Loan Facility

We have a secured five-year term loan facility in an aggregate principal amount of $1.233 billion as of December 31, 2017. Our obligations under the facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility, second lien notes and senior notes and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 7.50% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 6.50% per annum, subject to a 2.00% ABR floor, at our option. The term loan matures in August 2021 and voluntary prepayments are subject to a make-whole premium prior to the second anniversary of the closing of the term loan, a premium to par of 4.25% from the second anniversary until but excluding the third anniversary, a premium to par of 2.125% from the third anniversary until but excluding the fourth anniversary and at par beginning on the fourth anniversary. The term loan may be subject to mandatory prepayments and offers to purchase with net cash proceeds of certain issuances of debt, certain asset sales and other dispositions of collateral and upon a change of control.

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.

Revolving Credit Facility

We have a senior secured revolving credit facility currently subject to a $3.8 billion borrowing base that matures in December 2019. As of December 31, 2017, we had outstanding borrowings of $781 million under the revolving credit facility and had used $116 million of the revolving credit facility for various letters of credit. Borrowings under the revolving credit facility bear interest at a variable rate. The terms of the revolving credit facility include covenants limiting, among other things, our ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates.

In the fourth quarter of 2017, we completed a scheduled borrowing base redetermination review and our lenders reaffirmed our $3.8 billion borrowing base. Our next borrowing base redetermination is scheduled for the second quarter of 2018.

We entered into a third amendment to our revolving credit facility in 2016, and a fourth amendment in 2017. After giving effect to those amendments, our revolving credit facility currently requires that we maintain a net debt to capitalization ratio of not greater than 65%, a first lien secured leverage ratio of not more than 3.50 to 1.0 on December 31, 2017 and 3.00 to 1.0 thereafter and an interest coverage ratio of at least 1.25 to 1.0. In the third amendment, we agreed to grant liens and security interests on a majority of our assets. The third amendment also gave us the ability to incur first lien indebtedness 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. The amount of such additional first lien indebtedness currently permitted by the revolving credit facility is $1.3 billion.

As of December 31, 2017, we were in compliance with all applicable financial covenants under the credit agreement and we were able to borrow up to the full availability under the revolving credit facility.

Fair Value of Debt

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

	December 31, 2017		December 31, 2016	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$ 52	$ 53	$ 503	$ 511
Long-term debt (Level 1)	$ 2,633	$ 2,629	$ 3,271	$ 3,216
Long-term debt (Level 2)	$ 7,286	$ 7,301	$ 6,664	$ 6,654

4. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

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

Regulatory and Related Proceedings. We have received U.S. Postal Service and state subpoenas seeking information on our royalty payment practices. We have engaged in discussions with the U.S. Postal Service and state agency representatives and continue to respond to related subpoenas and demands.

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

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

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

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the divestiture of substantially all of our midstream business and most of our gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights, intentional interference with contractual relations, and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources. These lawsuits seek in aggregate compensatory, consequential, treble, and punitive damages, restitution and disgorgement of profits, declaratory and injunctive relief regarding our royalty payment practices, pre-and post-judgment interest, and attorney's fees and costs. On December 20, 2017, we reached a tentative settlement to resolve substantially all Pennsylvania civil royalty cases for approximately $30 million.

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

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

Environmental Contingencies

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

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

Other Matters

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

Commitments

Operating Leases

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

	December 31, 2017
	($ in millions)
2018	$ 6
2019	5
2020	2
2021	1
Total	$ 14

Lease expense for the years ended December 31, 2017, 2016 and 2015, was $3 million, $5 million and $7 million, respectively.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of oil, natural gas and NGL to move certain of our production to market. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded as obligations in the accompanying consolidated balance sheets; however, they are reflected in our estimates of proved reserves.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners, credits for third-party volumes or future costs under cost-of-service agreements, are presented below:

	December 31, 2017
	($ in millions)
2018	$ 1,079
2019	1,051
2020	979
2021	883
2022	771
2023 – 2035	4,404
Total	$ 9,167

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

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, 2017, the aggregate undiscounted minimum future payments under these drilling service commitments were approximately $23 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 remaining volumetric production payment (VPP) transaction. 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.

Other Commitments

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

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

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, 2017 and 2016 are detailed below:

	December 31,	
	2017	2016
	($ in millions)	
Revenues and royalties due others	$ 612	$ 543
Accrued drilling and production costs	216	169
Joint interest prepayments received	74	71
Accrued compensation and benefits	214	239
Other accrued taxes	43	32
Bank of New York Mellon legal accrual[a]	—	440
Other	296	304
Total other current liabilities	$ 1,455	$ 1,798

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(a) In 2017, we received notice from the U.S. Supreme Court that it would not review our appeal of the decision by the U.S. District Court for the Southern District of New York regarding the early redemption of our 6.775% Senior Notes due 2019. As a result of the decision, we paid $441 million with cash on hand and borrowings under the credit facility, and the related supersedeas bond was released.

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

	December 31,	
	2017	2016
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$ 156	$ 160
Unrecognized tax benefits	101	97
Other	97	126
Total other long-term liabilities	$ 354	$ 383

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(a) The CHK Utica, L.L.C. investors' right to receive proportionately an overriding royalty interest (ORRI) in the first 1,500 net wells drilled on certain of our Utica Shale leasehold runs through 2023. We have the right to repurchase the ORRIs in the remaining net wells once we have drilled a minimum of 1,300 net wells. As of December 31, 2017, we had drilled 572 net wells. The obligation to deliver future ORRIs, which has been recorded as a liability, will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis. As of December 31, 2017 and 2016, approximately $30 million and $43 million of the total ORRI obligations are recorded in other current liabilities, respectively.

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,		
	2017	2016	2015
	($ in millions)		
Current			
Federal	$ (14)	$ (14)	$ —
State	5	(5)	(36)
Current Income Taxes	(9)	(19)	(36)
Deferred			
Federal	13	(147)	(4,385)
State	(2)	(24)	(42)
Deferred Income Taxes	11	(171)	(4,427)
Total	$ 2	$ (190)	$ (4,463)

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,		
	2017	2016	2015
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (35%)	$ 333	$ (1,606)	$ (6,684)
State income taxes (net of federal income tax benefit)	66	(30)	(406)
Remeasurement of deferred tax assets and liabilities	1,266	—	—
Change in valuation allowance	(1,676)	1,423	2,727
Other	13	23	(100)
Total	$ 2	$ (190)	$ (4,463)

On December 22, 2017, the President of the United States signed into law the Tax Act, which substantially revised numerous areas of U.S. federal income tax law, including lowering the tax rate for corporations from a maximum rate of 35% to a flat rate of 21% and eliminating the corporate alternative minimum tax (AMT). These changes are generally in effect for tax years beginning after December 31, 2017. Although we are still in the process of evaluating the full impact of the Tax Act, the table above reflects the adjustments for remeasurement of deferred tax assets and liabilities. This remeasurement did not impact our income tax provision or balance sheet due to the offsetting effect of adjusting the valuation allowance. Due to various estimates included in determining the tax provision, the remeasurement is considered provisional and may be adjusted through subsequent events such as the filing of our consolidated federal income tax return for the period ended December 31, 2017.

We reassessed the realizability of our deferred tax assets and continue to maintain a valuation allowance against a significant portion of our net deferred tax assets excluding the deferred tax assets related to AMT credit carryovers that are expected to be realized in the future. The $1.676 billion net decrease in our valuation allowance is reflected as a component of income tax expense in our consolidated statement of operations for the year ended December 31, 2017. This decrease is primarily due to offsetting the provisional remeasurement of deferred tax assets and liabilities as a result of the Tax Act, as well as an offset to current year tax expense.

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

	Years Ended December 31,	
	2017	2016
	($ in millions)	
Deferred tax liabilities:		
Volumetric production payments	$ (129)	$ (223)
Other	(20)	(62)
Deferred tax liabilities	(149)	(285)
Deferred tax assets:		
Property, plant and equipment	1	593
Net operating loss carryforwards	2,248	2,587
Carrying value of debt	161	539
Asset retirement obligations	42	98
Investments	161	275
Derivative instruments	17	161
Accrued liabilities	125	319
Other	71	118
Deferred tax assets	2,826	4,690
Valuation allowance	(2,674)	(4,389)
Net deferred tax assets	152	301
Net deferred tax assets	$ 3	$ 16

As of December 31, 2017, we had federal NOL carryforwards of approximately $8.073 billion and state NOL carryforwards of approximately $10.066 billion, which excludes the NOL carryforwards related to unrecognized tax benefits. The associated deferred tax assets related to these federal and state NOL carryforwards were $1.695 billion and $581 million, respectively. The NOL carryforwards expire between 2031 and 2037. The value of these carryforwards depends on our ability to generate taxable income. As of December 31, 2017 and 2016, we had deferred tax assets of $2.826 billion and $4.690 billion upon which we had a valuation allowance of $2.674 billion and $4.389 billion, respectively. Of the net change in the valuation allowance of $1.715 billion for both federal and state deferred tax assets, $1.676 billion is reflected as a component of income tax expense in the consolidated statement of operations and the remainder is reflected in components of stockholders' equity.

A valuation allowance for deferred tax assets, including NOL carryforwards, is recognized when it is more-likely- than-not that all or some portion 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. Management assesses all 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 objectively verifiable negative evidence is the cumulative loss incurred over the three-year period ending December 31, 2017. Such objective negative evidence limits our ability to consider various forms of subjective positive evidence, such as our projections for future income. Accordingly, management has not changed its judgement with respect to the need for a valuation allowance against substantially all of our net deferred tax asset position. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective positive evidence such as future expected growth.

Our ability to utilize NOL carryforwards to reduce future federal taxable income and federal income tax is subject to various limitations under the Code. 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 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, 2017, we do not believe that an ownership change has occurred that would limit our NOL carryforwards. Certain future transactions involving our equity (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOL carryforwards and possibly other tax attributes.

Accounting guidance for recognizing and measuring uncertain tax positions requires a more-likely-than-not threshold condition be met on a tax position, based solely on the technical merits of being sustained, before any benefit of the tax position can be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. As of December 31, 2017 and 2016, the amount of unrecognized tax benefits related to NOL carryforwards and tax liabilities associated with uncertain tax positions was $106 million and $202 million, respectively. Of the 2017 amount, $74 million is related to state tax liabilities, $4 million is related to federal tax liabilities and the remainder is related to NOL carryforwards. Of the 2016 amount, $76 million is related to state tax liabilities while the remainder is related to NOL carryforwards. If recognized, $74 million of the uncertain tax positions identified would have an effect on the effective tax rate. No material changes to the current uncertain tax positions are expected within the next 12 months. As of December 31, 2017 and 2016, we had accrued liabilities of $23 million and $20 million, respectively, for interest related to these uncertain tax positions. We recognize interest related to uncertain tax positions as a component of interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

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

	2017	2016	2015
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 202	$ 280	$ 303
Additions based on tax positions related to the current year	—	—	27
Additions to tax positions of prior years	4	33	—
Settlements	(100)	(111)	—
Reductions to tax positions of prior years	—	—	(50)
Unrecognized tax benefits at end of period	$ 106	$ 202	$ 280

Our 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. During the 2017 fourth quarter, we reached a tentative settlement with the IRS in regards to our 2010 to 2013 federal income tax returns. Even though the audit remains open, we have concluded that uncertain tax positions related to these respective years are effectively settled and the corresponding unrecognized tax benefits have now been recorded. The 2010 through 2017 years and the 2007 through 2017 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 FTSI. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs. For the years ended December 31, 2017, 2016 and 2015, our expenditures for hydraulic fracturing services with FTSI were $111 million, $3 million and $65 million, respectively.

8. Equity

Common Stock

A summary of the changes in our common shares issued for the years ended December 31, 2017, 2016 and 2015 is detailed below:

	Years Ended December 31,		
	2017	2016	2015
		(in thousands)	
Shares issued as of January 1	896,279	664,796	664,944
Exchange of convertible notes	—	55,428	—
Exchange of senior notes	—	53,924	—
Exchange/conversion of preferred stock	9,966	120,186	—
Restricted stock issuances (net of forfeitures and cancellations)	2,488	1,945	(163)
Stock option exercises	—	—	15
Shares issued as of December 31	908,733	896,279	664,796

During the year ended December 31, 2017, our shareholders approved an amendment to our certificate of incorporation to increase our authorized common stock to 2,000,000,000 shares, par value $0.01 per share.

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2017:

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

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

Outstanding shares of our preferred stock for the years ended December 31, 2017, 2016 and 2015 are detailed below:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2017	843	476	2,559	1,962
Preferred stock conversions/exchanges[(a)]	(73)	(13)	—	(151)
Shares outstanding as of December 31, 2017	770	463	2,559	1,811
Shares outstanding as of January 1, 2016	1,497	1,100	2,559	2,096
Preferred stock conversions/exchanges[(b)]	(654)	(624)	—	(134)
Shares outstanding as of December 31, 2016	843	476	2,559	1,962
Shares outstanding as of January 1, 2015 and December 31, 2015	1,497	1,100	2,559	2,096

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

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

Dividends

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

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

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

Accumulated Other Comprehensive Income (Loss)

For the years ended December 31, 2017 and 2016, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below:

	Years Ended December 31,	
	2017	2016
	($ in millions)	
Balance, as of January 1	$ (96)	$ (99)
Other comprehensive income (loss) before reclassifications	5	(13)
Amounts reclassified from accumulated other comprehensive income	34	16
Net other comprehensive income (loss)	39	3
Balance, as of December 31	$ (57)	$ (96)

For the years ended December 31, 2017 and 2016, net losses on cash flow hedges for commodity contracts reclassified from accumulated other comprehensive income (loss), net of tax, to oil, natural gas and NGL revenues in the consolidated statements of operations were $34 million and $16 million, respectively.

Noncontrolling Interests

Chesapeake Granite Wash Trust. In 2011, Chesapeake Granite Wash Trust (the Trust) sold 23,000,000 common units representing beneficial interests in the Trust to the public. Prior to June 30, 2017, we owned 12,062,500 common units and as well as 11,687,500 subordinated units representing a 51% beneficial interest in the Trust. On June 30, 2017, the Trust's subordinated units, all of which were held by us, converted to common units. The Trust has a total of 46,750,000 units outstanding.

Prior to their conversion on June 30, 2017, as holder of the subordinated units, we were entitled to receive pro rata distributions from the Trust each quarter if and to the extent there was sufficient cash. We were also entitled to receive, prior to their termination on June 30, 2017, incentive distributions, to the extent of sufficient cash, as defined. No subordinated unit or incentive distributions were made by the Trust.

During our review of the carrying amount of the Trust's noncontrolling interests, we identified errors related to the allocation of impairment expense between Chesapeake and the Trust's noncontrolling interests during previously reported periods. We have determined that these errors are immaterial to previously issued financial statements and therefore, have revised the previously reported financial statements below. We have also determined that these errors did not relate to periods prior to 2015.

	December 31, 2016		
CONSOLIDATED BALANCE SHEETS	As Previously Reported	Revision Adjustment	As Revised
	($ in millions except per share data)		
Accumulated deficit	$ (17,603)	$ 129	$ (17,474)
Total Chesapeake stockholders' equity (deficit)	$ (1,460)	$ 129	$ (1,331)
Noncontrolling interests	$ 257	$ (129)	$ 128

CONSOLIDATED STATEMENTS OF OPERATIONS	Year Ended December 31, 2016		
	As Previously Reported	Revision Adjustment	As Revised
	($ in millions except per share data)		
Net (income) loss attributable to noncontrolling interest	$ (2)	$ 11	$ 9
Net income (loss) attributable to Chesapeake	$ (4,401)	$ 11	$ (4,390)
Net income (loss) available to common stockholders	$ (4,926)	$ 11	$ (4,915)
Loss per common share basic	$ (6.45)	$ 0.02	$ (6.43)
Loss per common share diluted	$ (6.45)	$ 0.02	$ (6.43)

CONSOLIDATED STATEMENTS OF OPERATIONS	Year Ended December 31, 2015		
	As Previously Reported	Revision Adjustment	As Revised
	($ in millions except per share data)		
Net (income) loss attributable to noncontrolling interest	$ (50)	$ 118	$ 68
Net income (loss) attributable to Chesapeake	$ (14,685)	$ 118	$ (14,567)
Net income (loss) available to common stockholders	$ (14,856)	$ 118	$ (14,738)
Loss per common share basic	$ (22.43)	$ 0.17	$ (22.26)
Loss per common share diluted	$ (22.43)	$ 0.17	$ (22.26)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	Year Ended December 31, 2016		
	As Previously Reported	Revision Adjustment	As Revised
	($ in millions except per share data)		
Comprehensive (income) loss attributable to noncontrolling interests	$ (2)	$ 11	$ 9
Comprehensive income (loss) attributable to Chesapeake	$ (4,398)	$ 11	$ (4,387)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME	Year Ended December 31, 2015		
	As Previously Reported	Revision Adjustment	As Revised
	($ in millions except per share data)		
Comprehensive (income) loss attributable to noncontrolling interests	$ (50)	$ 118	$ 68
Comprehensive income (loss) attributable to Chesapeake	$ (14,641)	$ 118	$ (14,523)

	Year Ended December 31, 2016		
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	**As Previously Reported**	**Revision Adjustment**	**As Revised**
	($ in millions except per share data)		
Accumulated deficit	$ (17,603)	$ 129	$ (17,474)
Noncontrolling interests	$ 257	$ (129)	$ 128

	Year Ended December 31, 2015		
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY	**As Previously Reported**	**Revision Adjustment**	**As Revised**
	($ in millions except per share data)		
Accumulated deficit	$ (13,202)	$ 118	$ (13,084)
Noncontrolling interests	$ 259	$ (118)	$ 141

We have determined that the Trust is a VIE and that we are the primary beneficiary. As a result, the Trust is included in our consolidated financial statements. As of December 31, 2017 and 2016, we had $124 million and $128 million, respectively, of noncontrolling interests on our consolidated balance sheets attributable to the Trust. Net income attributable to the Trust's noncontrolling interest was $4 million for the year ended December 31, 2017 and net loss attributable to the Trust's noncontrolling interest was $9 million and $68 million for the years ended December 31, 2016 and 2015, respectively.

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

Cleveland Tonkawa Financial Transaction. We formed CHK C-T in 2012 to continue development of a portion of our oil and natural gas assets in our Cleveland and Tonkawa plays, in which 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.

During 2015, CHK C-T sold all of its oil and natural gas properties to FourPoint Energy, LLC. See Note 12 for further discussion of this transaction. In connection with this transaction, we eliminated all related future drilling and ORRI commitments attributable to CHK C-T.

Net income attributable to the noncontrolling interests of CHK C-T was $50 million for the year ended December 31, 2015.

9. Share-Based Compensation

Our 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.

Share-Based Compensation Plans

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

The 2014 LTIP authorizes the issuance of the following types of awards: (i) nonqualified and incentive stock options; (ii) SARs; (iii) restricted stock; (iv) performance awards, including PSUs; and (v) other stock-based awards. For both stock options and SARs, the exercise price may not be less than the fair market value of our common stock on the date of grant and the maximum exercise period may not exceed ten years from the date of grant. Awards granted under the plan vest at specified dates and/or upon the satisfaction of certain performance or other criteria, as determined by the Compensation Committee. As of December 31, 2017, 40,574,965 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. A summary of the changes in unvested restricted stock during 2017, 2016 and 2015 is presented below:

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

The aggregate intrinsic value of restricted stock that vested during 2017 was approximately $26 million based on the stock price at the time of vesting.

As of December 31, 2017, there was approximately $47 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 1.88 years.

Stock Options. In 2017, 2016 and 2015, we granted members of management stock options that vest ratably over a three-year period. Each stock option award has an exercise price equal to the closing price of our common stock on the grant date. Outstanding options expire seven years to ten years from the date of grant.

We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The expected life of an option is determined using the simplified method. Volatility assumptions are estimated based on an average of historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account our dividend policy, over the expected life of the option. The Company used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in 2017:

Expected option life – years	6.0
Volatility	62.42%
Risk-free interest rate	2.17%
Dividend yield	—%

The following table provides information related to stock option activity for 2017, 2016 and 2015:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[a]
	(in thousands)			($ in millions)
Outstanding as of January 1, 2017	8,593	$ 11.88	7.22	$ 14
Granted	9,226	$ 5.45		
Exercised	—	$ —		$ —
Expired	(435)	$ 18.51		
Forfeited	(1,099)	$ 9.12		
Outstanding as of December 31, 2017	16,285	$ 8.25	7.73	$ 1
Exercisable as of December 31, 2017	4,474	$ 15.15	5.26	$ —
Outstanding as of January 1, 2016	5,377	$ 19.37	5.80	$ —
Granted	4,932	$ 3.71		
Exercised	—	$ —		$ —
Expired	(771)	$ 19.46		
Forfeited	(945)	$ 5.66		
Outstanding as of December 31, 2016	8,593	$ 11.88	7.22	$ 14
Exercisable as of December 31, 2016	2,844	$ 19.60	5.53	$ —
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	$ —

(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, 2017, there was $22 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.08 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, 2017, 2016 and 2015:

	Years Ended December 31,		
	2017	2016	2015
		($ in millions)	
General and administrative expenses	$ 37	$ 38	$ 43
Oil and natural gas properties	12	16	23
Oil, natural gas and NGL production expenses	12	13	18
Marketing, gathering and compression expenses	—	1	5
Total restricted stock and stock option compensation	$ 61	$ 68	$ 89

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 2017 and 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%. 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 our estimates of the underlying performance measures. The payout percentage for all PSU grants is capped at 100% if the Company’s absolute TSR is less than zero. We utilized a Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs.

Volatility	83.97%
Risk-free interest rate	1.89%
Dividend yield for value of awards	—%

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

	Units	Grant Date Fair Value	December 31, 2017 Fair Value	December 31, 2017 Vested Liability
		($ in millions)	($ in millions)	
2017 Awards:				
Payable 2020	1,217,774	$ 8	$ 5	$ 3
2016 Awards:				
Payable 2019	2,348,893	$ 10	$ 9	$ 8
2015 Awards:				
Payable 2018	629,694	$ 13	$ 1	$ 1

PSU Compensation. We recognized the following compensation costs (credits) related to PSUs for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31, 2017	2016	2015
	($ in millions)		
General and administrative expenses	$ (4)	$ 14	$ (19)
Restructuring and other termination costs	—	1	(19)
Marketing, gathering and compression	—	—	(1)
Oil and natural gas properties	—	—	(2)
Total PSU compensation	$ (4)	$ 15	$ (41)

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. We match employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's base salary and performance bonus) in cash. We contributed $35 million, $39 million and $52 million to the 401(k) Plan in 2017, 2016 and 2015, respectively.

We also maintain a nonqualified deferred compensation plan (DC Plan). To be eligible to participate in the DC Plan, an active employee must have a base salary of at least $150,000, have a hire date on or before December 1, immediately preceding the year in which the employee is able to participate, or be designated as eligible to participate. Only the top 10% of our wage earners are eligible to participate. We match 100% of employee contributions up to 15% of base salary and performance bonus in the aggregate for the DC Plan with Chesapeake common stock, and an employee who is at least age 55 may elect for the matching contributions to be made in any one of the DC Plan's investment options. The maximum compensation that can be deferred by employees under all of our deferred compensation plans, including the Chesapeake 401(k) Plan, is a total of 75% of base salary and 100% of performance bonus. We contributed $8 million, $9 million and $11 million to the DC Plan during 2017, 2016 and 2015, 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 us to fund future obligations of our 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

We use derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility. All of our oil, natural gas and NGL derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty. None of our oil, natural gas and NGL derivative instruments were designated for hedge accounting as of December 31, 2017 and 2016.

Oil, Natural Gas and NGL Derivatives

As of December 31, 2017 and 2016, our oil, natural gas and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options and call swaptions.
- *Options*: We sell, and occasionally 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, we pay the counterparty the excess on sold call options and we receive the excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- *Call Swaptions*: We sell call swaptions to counterparties that allow the counterparty, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- *Collars*: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include the sale by us of an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *Basis Protection Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and 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, 2017 and 2016 are provided below:

	December 31, 2017		December 31, 2016	
	Notional Volume	Fair Value	Notional Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	21	$ (151)	23	$ (140)
Three-way collars	2	(10)	—	—
Call options	—	—	5	(1)
Call swaptions	2	(13)	—	—
Basis protection swaps	11	(9)	—	—
Total oil	36	(183)	28	(141)
Natural gas (tbtu):				
Fixed-price swaps	532	149	719	(349)
Collars	47	11	60	(9)
Call options	110	(3)	114	—
Basis protection swaps	65	(7)	31	(5)
Total natural gas	754	150	924	(363)
NGL (mmgal):				
Fixed-price swaps	33	(2)	53	—
Total estimated fair value		$ (35)		$ (504)

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

Foreign Currency Derivatives

During 2017, both our 6.25% Euro-denominated Senior Notes due 2017 and cross currency swaps for the same principal amount matured. Upon maturity of the notes, the counterparties paid us €246 million and we paid the counterparties $327 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. The swaps were designated as cash flow hedges and, because they were entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value did not impact earnings. The fair values of the cross currency swaps were recorded on the consolidated balance sheet as a liability of $73 million as of December 31, 2016.

Supply Contract Derivatives

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

Effect of Derivative Instruments – Consolidated Balance Sheets

The following table presents the fair value and location of each classification of derivative instrument included in the consolidated balance sheets as of December 31, 2017 and 2016 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in the Consolidated Balance Sheets	Net Fair Value Presented in the Consolidated Balance Sheet
		($ in millions)	
As of December 31, 2017			
Commodity Contracts:			
Short-term derivative asset	$ 157	$ (130)	$ 27
Short-term derivative liability	(188)	130	(58)
Long-term derivative liability	(4)	—	(4)
Total commodity contracts	(35)	—	(35)
Total derivatives	$ (35)	$ —	$ (35)
As of December 31, 2016			
Commodity Contracts:			
Short-term derivative asset	$ 1	$ (1)	$ —
Short-term derivative liability	(490)	1	(489)
Long-term derivative liability	(15)	—	(15)
Total commodity contracts	(504)	—	(504)
Foreign Currency Contracts:[a]			
Short-term derivative liability	(73)	—	(73)
Total foreign currency contracts	(73)	—	(73)
Total derivatives	$ (577)	$ —	$ (577)

(a) Designated as cash flow hedging instruments.

As of December 31, 2017 and 2016, 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, 2017, 2016 and 2015 are presented below:

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Oil, natural gas and NGL revenues	4,574	3,866	4,767
Gains (losses) on undesignated oil, natural gas and NGL derivatives	445	(545)	661
Losses on terminated cash flow hedges	(34)	(33)	(37)
Total oil, natural gas and NGL revenues	$ 4,985	$ 3,288	$ 5,391

The components of marketing, gathering and compression revenues for the years ended December 31, 2017, 2016 and 2015 are presented below:

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Marketing, gathering and compression revenues	$ 4,511	$ 4,881	$ 7,077
Losses on undesignated supply contract derivatives	—	(297)	296
Total marketing, gathering and compression revenues	$ 4,511	$ 4,584	$ 7,373

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,					
	2017		2016		2015	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (153)	$ (96)	$ (160)	$ (99)	$ (231)	$ (143)
Net change in fair value	5	5	(27)	(13)	32	20
Losses reclassified to income	34	34	34	16	39	24
Balance, end of period	$ (114)	$ (57)	$ (153)	$ (96)	$ (160)	$ (99)

The accumulated other comprehensive loss as of December 31, 2017 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the original contract months are yet to occur. Remaining deferred gain or loss amounts will be recognized in earnings in the month for which the original contract months are to occur. As of December 31, 2017, we expect to transfer approximately $17 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amounts will be transferred by December 31, 2022.

Credit Risk Considerations

Our derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are highly rated or deemed by us to have acceptable credit strength and deemed by management to be competent and competitive market-makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2017, our oil, natural gas and NGL derivative instruments were spread among 11 counterparties.

Hedging Arrangements

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

Fair Value

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

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2017 and 2016:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of December 31, 2017				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ —	$ 8	$ 8
Commodity liabilities	—	(20)	(23)	(43)
Total derivatives	$ —	$ (20)	$ (15)	$ (35)
As of December 31, 2016				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 1	$ —	$ 1
Commodity liabilities	—	(495)	(10)	(505)
Foreign currency liabilities	—	(73)	—	(73)
Total derivatives	$ —	$ (567)	$ (10)	$ (577)

A summary of the changes in the fair values of our financial assets (liabilities) classified as Level 3 during 2017 and 2016 is presented below:

	Commodity Derivatives		Supply Contracts	
	($ in millions)			
Balance, as of January 1, 2017	$	(10)	$	—
Total gains (losses) (realized/unrealized):				
Included in earnings[(a)]		2		—
Total purchases, issuances, sales and settlements:				
Settlements		(7)		—
Balance, as of December 31, 2017	$	(15)	$	—
Balance, as of January 1, 2016	$	(91)	$	297
Total gains (losses) (realized/unrealized):				
Included in earnings[(a)]		6		(118)
Total purchases, issuances, sales and settlements:				
Settlements		75		(33)
Sales		—		(146)
Balance, as of December 31, 2016	$	(10)	$	—

(a)

	Commodity Derivatives				Marketing, Gathering and Compression Revenue			
	2017		2016		2017		2016	
	($ in millions)							
Total gains (losses) included in earnings for the period	$	2	$	6	$	—	$	(118)
Change in unrealized gains (losses) related to assets still held at reporting date	$	(14)	$	(7)	$	—	$	—

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

The significant unobservable inputs for Level 3 derivative contracts include 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, 2017:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2017	
				($ in millions)	
Oil trades	Oil price volatility curves	13.14% – 24.93%	22.43%	$	(23)
Natural gas trades	Natural gas price volatility curves	18.82% – 82.61%	38.06%	$	8

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.

2017 Transactions

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

We received proceeds of approximately $350 million, net of post-closing adjustments, for the sale of other oil and natural gas properties covering various operating areas.

2016 Transactions

We conveyed our interests in the Barnett Shale operating area located in north central Texas and received from the buyer aggregate net proceeds of approximately $218 million. 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.

Joint Ventures

In 2017, 2016 and 2015, 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 $10 million, $7 million and $33 million, respectively.

Volumetric Production Payments

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

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

We have committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

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. VPP#8 expired in August 2015.

As of December 31, 2017, we had the following VPP outstanding:

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

The volumes remaining to be delivered on behalf of our VPP buyers as of December 31, 2017 were as follows:

		Volume Remaining as of December 31, 2017			
VPP #	Term Remaining	Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	38	0.4	34.1	0.9	41.7

13. Other Property and Equipment

Other Property and Equipment

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

	December 31,		Estimated Useful Life
	2017	2016	
	($ in millions)		(in years)
Buildings and improvements	$ 1,093	$ 1,119	10 – 39
Computer equipment	345	337	5
Natural gas compressors	235	251	3 – 20
Land	126	139	
Gathering systems and treating plants	2	2	20
Other	185	205	5 – 10
Total other property and equipment, at cost	1,986	2,053	
Less: accumulated depreciation	(672)	(632)	
Total other property and equipment, net	$ 1,314	$ 1,421	

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, 2017, 2016 and 2015 is as follows:

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Buildings and land	$ (4)	$ (1)	$ 3
Natural gas compressors	1	(10)	—
Gathering systems and treating plants	—	—	1
Other	—	(1)	—
Total net (gains) losses on sales of fixed assets	$ (3)	$ (12)	$ 4

Assets Held for Sale

We are continuing to pursue the sale of buildings and land located primarily in Oklahoma and West Virginia. 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, 2017. 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, 2017 and 2016, we had $16 million and $29 million, respectively, of buildings, land and compressors net of accumulated depreciation, classified as assets held for sale on our consolidated balance sheets.

14. 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 2017, we did not have an impairment for our oil and natural gas properties. In 2016 and 2015, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment in the carrying value of our oil and natural gas properties of $2.564 billion and $18.238 billion, respectively.

Impairments of Fixed Assets and Other

We review our long-lived assets, other than oil and natural gas properties, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable. We recognize an impairment if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. A summary of our impairments of fixed assets by asset class and other charges for the years ended December 31, 2017, 2016 and 2015 is as follows:

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Barnett Shale exit costs	$ —	$ 645	$ —
Devonian Shale exit costs	—	142	—
Gathering systems	—	3	—
Natural gas compressors	—	21	21
Buildings and land	5	11	—
Other charges	416	16	173
Total impairments of fixed assets and other	$ 421	$ 838	$ 194

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.

Other. In 2017, we terminated future natural gas transportation commitments related to divested assets for cash payments of $126 million. In 2017, we also paid $290 million to assign an oil transportation agreement to a third party.

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, 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.

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

15. 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.

Other

We recognized credits of $19 million in 2015 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.

16. Fair Value Measurements

Recurring Fair Value Measurements

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

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

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

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in millions)			
As of December 31, 2017				
Financial Assets (Liabilities):				
Other current assets	$ 57	$ —	$ —	$ 57
Other current liabilities	(60)	—	—	(60)
Total	$ (3)	$ —	$ —	$ (3)
As of December 31, 2016				
Financial Assets (Liabilities):				
Other current assets	$ 49	$ —	$ —	$ 49
Other current liabilities	(51)	—	—	(51)
Total	$ (2)	$ —	$ —	$ (2)

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 14 regarding nonrecurring fair value measurements.

17. Asset Retirement Obligations

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

	Years Ended December 31, 2017	2016
	($ in millions)	
Asset retirement obligations, beginning of period	$ 261	$ 473
Additions	5	4
Revisions	(34)	(58)
Settlements and disposals	(70)	(182)
Accretion expense	15	24
Asset retirement obligations, end of period	177	261
Less current portion	15	14
Asset retirement obligation, long-term	$ 162	$ 247

18. Major Customers

Sales to Royal Dutch Shell PLC constituted approximately 10% of our total revenues (before the effects of hedging) for the year ended December 31, 2017. Sales to BP PLC constituted approximately 10% and 14% of our total revenues (before the effects of hedging) for the years ended December 31, 2016 and 2015, respectively.

19. Condensed Consolidating Financial Information

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

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

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

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

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

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 4,962	$ 23	$ —	$ 4,985
Marketing, gathering and compression	—	4,511	—	—	4,511
Total Revenues	—	9,473	23	—	9,496
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	562	—	—	562
Oil, natural gas and NGL gathering, processing and transportation	—	1,463	8	—	1,471
Production taxes	—	88	1	—	89
Marketing, gathering and compression	—	4,598	—	—	4,598
General and administrative	1	259	2	—	262
Restructuring and other termination costs	—	—	—	—	—
Provision for legal contingencies, net	(79)	41	—	—	(38)
Oil, natural gas and NGL depreciation, depletion and amortization	—	909	4	—	913
Depreciation and amortization of other assets	—	82	—	—	82
Impairments of fixed assets and other	—	421	—	—	421
Net gains on sales of fixed assets	—	(3)	—	—	(3)
Total Operating Expenses	(78)	8,420	15	—	8,357
INCOME FROM OPERATIONS	78	1,053	8	—	1,139
OTHER INCOME (EXPENSE):					
Interest expense	(424)	(2)	—	—	(426)
Gains on purchases or exchanges of debt	233	—	—	—	233
Other income	1	8	—	—	9
Equity in net earnings (losses) of subsidiary	1,063	4	—	(1,067)	—
Total Other Income (Expense)	873	10	—	(1,067)	(184)
INCOME BEFORE INCOME TAXES	951	1,063	8	(1,067)	955
INCOME TAX EXPENSE (BENEFIT)	2	—	—	—	2
NET INCOME	949	1,063	8	(1,067)	953
Net income attributable to noncontrolling interests	—	—	(4)	—	(4)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	949	1,063	4	(1,067)	949
Other comprehensive income	—	39	—	—	39
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 949	$ 1,102	$ 4	$ (1,067)	$ 988

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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ 5	$ 736	$ 14	$ (10)	$ 745
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(2,186)	—	—	(2,186)
Acquisitions of proved and unproved properties	—	(285)	—	—	(285)
Proceeds from divestitures of proved and unproved properties	—	1,249	—	—	1,249
Additions to other property and equipment	—	(21)	—	—	(21)
Other investing activities	—	55	—	—	55
Net Cash Used In Investing Activities	—	(1,188)	—	—	(1,188)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility borrowings	7,771	—	—	—	7,771
Payments on revolving credit facility borrowings	(6,990)	—	—	—	(6,990)
Proceeds from issuance of senior notes, net	1,585	—	—	—	1,585
Cash paid to purchase debt	(2,592)	—	—	—	(2,592)
Cash paid for preferred stock dividends	(183)	—	—	—	(183)
Other financing activities	(39)	(5)	(13)	32	(25)
Intercompany advances, net	(456)	456	—	—	—
Net Cash Provided by (Used In) Financing Activities	(904)	451	(13)	32	(434)
Net increase (decrease) in cash and cash equivalents	(899)	(1)	1	22	(877)
Cash and cash equivalents, beginning of period	904	2	1	(25)	882
Cash and cash equivalents, end of period	$ 5	$ 1	$ 2	$ (3)	$ 5

20. Subsequent Events

Subsequent to December 31, 2017, we underwent a reduction in workforce impacting approximately 13% of employees across all functions, primarily on our Oklahoma City campus.

Subsequent to December 31, 2017, we sold approximately 4.3 million shares of FTSI International for net proceeds of approximately $74 million. We continue to hold approximately 22.0 million shares in the publicly traded company.

Subsequent to December 31, 2017, we entered into agreements for the sale of properties in the Mid-Continent, including our Mississippian Lime assets, for expected aggregate proceeds of approximately $500 million. We expect to close these sales by the end of the 2018 second quarter, subject to customary closing conditions.

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2017 and 2016 are as follows:

	2017 First Quarter	2017 Second Quarter	2017 Third Quarter	2017 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 2,753	$ 2,281	$ 1,943	$ 2,519
Income from operations	$ 241	$ 399	$ 94	$ 405
Net income (loss) attributable to Chesapeake	$ 140	$ 494	$ (18)	$ 333
Net income (loss) available to common stockholders	$ 75	$ 470	$ (41)	$ 309
Net income (loss) per common share:				
Basic	$ 0.08	$ 0.52	$ (0.05)	$ 0.34
Diluted	$ 0.08	$ 0.47	$ (0.05)	$ 0.33

	2016 First Quarter	2016 Second Quarter	2016 Third Quarter	2016 Fourth Quarter
	($ in millions except per share data)			
Total revenues	$ 1,953	$ 1,622	$ 2,276	$ 2,021
Loss from operations	$ (1,099)	$ (1,783)	$ (1,234)	$ (295)
Net loss attributable to Chesapeake[(a)]	$ (1,061)	$ (1,775)	$ (1,212)	$ (342)
Net loss available to common stockholders[(a)]	$ (1,104)	$ (1,817)	$ (1,254)	$ (740)
Net loss per common share:				
Basic[(a)]	$ (1.65)	$ (2.51)	$ (1.61)	$ (0.83)
Diluted[(a)]	$ (1.65)	$ (2.51)	$ (1.61)	$ (0.83)

(a) During our review of the carrying amount of the Trust's noncontrolling interests, we identified errors related to the allocation of impairment expense between Chesapeake and the Trust's noncontrolling interests during previously reported periods. See Note 8 for additional information.

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

Net Capitalized Costs

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

	December 31, 2017	December 31, 2016
	($ in millions)	
Oil and oil and natural gas properties:		
Proved	$ 68,858	$ 66,451
Unproved	3,484	4,802
Total	72,342	71,253
Less accumulated depreciation, depletion and amortization	(62,992)	(62,094)
Net capitalized costs	$ 9,350	$ 9,159

Unproved properties not subject to amortization as of December 31, 2017 and 2016, consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. We capitalized approximately $194 million, $242 million and $410 million of interest during 2017, 2016 and 2015, 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, 2017	2016	2015
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ 23	$ 403	$ —
Unproved properties	271	403	454
Exploratory costs	21	52	112
Development costs	2,146	1,312	2,941
Costs incurred[(a)(b)]	$ 2,461	$ 2,170	$ 3,507

(a) Exploratory and development costs are net of $51 million in drilling and completion carries received from our joint venture partners during 2015.

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

Capitalized interest	$ 194	$ 242	$ 410
Asset retirement obligations[(c)]	$ (34)	$ (57)	$ (15)

(c) Includes revisions as a result of lower plugging and abandonment costs in some of our operating areas.

In 2017, we invested approximately $793 million to convert 125 mmboe of PUDs to proved developed reserves.

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

Our results of operations from oil, natural gas and NGL producing activities are presented below for 2017, 2016 and 2015. 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,		
	2017	2016	2015
	($ in millions)		
Oil, natural gas and NGL sales	$ 4,985	$ 3,288	$ 5,391
Oil, natural gas and NGL production expenses	(562)	(710)	(1,046)
Oil, natural gas and NGL gathering, processing and transportation expenses	(1,471)	(1,855)	(2,119)
Production taxes	(89)	(74)	(99)
Impairment of oil and natural gas properties	—	(2,564)	(18,238)
Depletion and depreciation	(913)	(1,003)	(2,099)
Imputed income tax provision[(a)]	(768)	1,027	6,683
Results of operations from oil, natural gas and NGL producing activities	$ 1,182	$ (1,891)	$ (11,527)

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

Oil, Natural Gas and NGL Reserve Quantities

Our petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2017, 2016 and 2015. Independent petroleum engineering firms estimated an aggregate of 83%, 70% and 59% of our estimated proved reserves (by volume) as of December 31, 2017, 2016 and 2015, respectively, as set forth below:

	December 31,		
	2017	2016	2015
Software Integrated Solutions, Division of Schlumberger Technology Corporation	83%	70%	23%
Ryder Scott Company, L.P.	—%	—%	36%

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 2017, 2016 and 2015:

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
December 31, 2017				
Proved reserves, beginning of period	399.1	6,496	226.4	1,708
Extensions, discoveries and other additions	62.7	3,694	44.9	723
Revisions of previous estimates	(168.1)	(315)	(31.0)	(252)
Production	(32.7)	(878)	(20.9)	(200)
Sale of reserves-in-place	(0.9)	(418)	(0.8)	(71)
Purchase of reserves-in-place	0.1	21	—	4
Proved reserves, end of period[a]	260.2	8,600	218.6	1,912
Proved developed reserves:				
Beginning of period	200.4	5,126	134.1	1,189
End of period	150.9	4,980	134.9	1,116
Proved undeveloped reserves:				
Beginning of period	198.7	1,370	92.2	519
End of period[b]	109.3	3,620	83.6	796

	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(c)	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
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(d)	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

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

(b) As of December 31, 2017, 2016 and 2015, there were no PUDs that had remained undeveloped for five years or more.

(c) 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.

(d) 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.

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

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

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.

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, 2017, 2016 and 2015 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
SUPPLEMENTARY INFORMATION – (Continued)

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,		
	2017	2016	2015
	($ in millions)		
Future cash inflows	$ 26,412 [(a)]	$ 19,835 [(b)]	$ 20,247 [(c)]
Future production costs	(7,044)	(6,800)	(7,391)
Future development costs	(4,977)	(3,621)	(1,518)
Future income tax provisions	—	(79)	(228)
Future net cash flows	14,391	9,335	11,110
Less effect of a 10% discount factor	(6,901)	(4,956)	(6,417)
Standardized measure of discounted future net cash flows[(d)]	$ 7,490	$ 4,379	$ 4,693

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

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

(c) Calculated using prices of $50.28 per bbl of oil and $2.58 per mcf of natural gas, before field differentials.

(d) Excludes discounted future net cash inflows attributable to production volumes sold to VPP buyers. See Note 12.

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

	Years Ended December 31,		
	2017	2016	2015
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 4,379	$ 4,693	$ 17,133
Sales of oil and natural gas produced, net of production costs and gathering, processing and transportation[(b)]	(2,452)	(1,227)	(1,503)
Net changes in prices and production costs	3,977	(1,210)	(18,070)
Extensions and discoveries, net of production and development costs	1,951	1,042	1,005
Changes in estimated future development costs	614	323	3,198
Previously estimated development costs incurred during the period	775	664	873
Revisions of previous quantity estimates	(1,255)	145	(3,472)
Purchase of reserves-in-place	3	394	1
Sales of reserves-in-place	(116)	13	(938)
Accretion of discount	441	473	2,201
Net change in income taxes	26	(8)	4,845
Changes in production rates and other	(853)	(923)	(580)
Standardized measure, end of period[(a)(c)]	$ 7,490	$ 4,379	$ 4,693

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

(b) Excludes gains and losses on derivatives.

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

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 Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded as of December 31, 2017 that our disclosure controls and procedures were effective.

Remediation of Previously Identified Material Weakness

As disclosed in our Annual Report on Form 10-K for the year ended December 31, 2016, our management determined that a material weakness existed in our internal control over financial reporting 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 calculation formula and the manual interface control that compared the data used in the tool to the general ledger was not designed at an appropriately disaggregated level.

We have taken the necessary steps to enhance the underlying control activities, which now include restricted access within the tool to maintain and control changes to the formulaic calculations, a manual interface control to validate that the automated interface configuration and calculation formulas are accurate, and a manual recalculation of the basis price differentials.

Based on the results of management’s evaluation, we have concluded that the controls are designed and operating effectively as of December 31, 2017 and, therefore, the previously disclosed material weakness has been remediated.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2017 that have materially affected, or are 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 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, 2018 (the 2018 Proxy Statement).

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the 2018 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 2018 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 2018 Proxy Statement.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the 2018 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 are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed or Furnished Herewith**
3.1.1	Chesapeake's Restated Certificate of Incorporation.	10-Q	001-13726	3.1.1	8/3/2017	
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008	
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008	
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010	
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010	
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/19/2014	
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	4.1.1	11/15/2005	
4.2*	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	
4.3*	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	
4.4.1*	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	

4.4.2	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
4.4.3	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
4.4.4	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
4.4.5	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
4.4.6	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
4.5.1**	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
4.5.2	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
4.5.3	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
4.6	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
4.7.1	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

4.7.2	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
4.7.3	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
4.7.4††	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
4.7.5	Fourth Amendment to Credit Agreement dated May 19, 2017 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.	8-K	001-13726	10.1	5/22/2017
4.8	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
4.9	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
4.10	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
4.11	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
4.12	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	10.1	8/24/2016

4.13	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	4.1	10/5/2016
4.14	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
4.15	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
4.16	Purchase Agreement, dated May 22, 2017, by and among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Citigroup Global Markets Inc., as representative of the initial purchasers named therein, relating to the private placement of the 8.00% Senior Notes due 2027.	8-K	001-13726	10.1	5/23/2017
4.17	Seventh Supplemental Indenture dated as of June 6, 2017 to Indenture dated as of April 24, 2014 with respect to 8.00% Senior Notes due 2027.	8-K	001-13726	4.2	6/7/2017
4.18	Registration Rights Agreement dated as of June 6, 2017, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Citigroup Global Markets Inc.	8-K	001-13726	4.4	6/7/2017
4.19	Purchase Agreement, dated September 27, 2017, by and among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Morgan Stanley & Co. LLC, as representative of the initial purchasers named therein, relating to the private placement of the 8.00% Senior Notes due 2025 and 8.00% Senior Notes due 2027.	8-K	001-13726	10.1	9/28/2017
4.20	Registration Rights Agreement, dated as of October 12, 2017, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Morgan Stanley & Co. LLC with respect to 8.00% Senior Notes due 2025.	8-K	001-13726	4.4	10/12/2017
4.21	Registration Rights Agreement, dated as of October 12, 2017, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Morgan Stanley & Co. LLC with respect to 8.00% Senior Notes due 2027.	8-K	001-13726	4.5	10/12/2017
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.	10-K	001-13726	10.3.2	3/3/2017	
10.4†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.	10-K	001-13726	10.16	3/1/2013	
10.5.1†	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	
10.5.2†	Amendment to Employment Agreement between Robert D. Lawler and Chesapeake Energy Corporation dated as of June 16, 2016.	8-K	001-13726	10.1	6/17/2016	
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. Jason Pigott and Chesapeake Energy Corporation.	8-K	001-13726	10.4	1/6/2016	
10.9†	Employment Agreement dated as of January 1, 2016 between Frank J. Patterson and Chesapeake Energy Corporation.					X

10.10†	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	
10.11†	Form of Indemnity Agreement for officers and directors of Chesapeake Energy Corporation and its subsidiaries.	8-K	001-13726	10.3	6/27/2012	
10.12†	Chesapeake Energy Corporation 2013 Annual Incentive Plan.	DEF 14A	001-13726	Exhibit G	5/3/2013	
10.12.1†	Chesapeake Energy Corporation Restated 2014 Long Term Incentive Plan.	10-Q	001-13726	10.1	8/3/2017	
10.12.2†	Form of Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.2	8/6/2014	
10.12.3†	Form of Restricted Stock Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.3	8/6/2014	
10.12.4†	Form of Nonqualified Stock Option Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.4	8/6/2014	
10.12.5†	Form of Performance Share Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.5	8/6/2014	
10.12.6†	Form of Director Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.6	8/6/2014	
10.13	Employment Agreement dated as of August 29, 2017 between Chesapeake Energy Corporation and William M. Buergler.	8-K	001-13726	10.1	9/1/2017	
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 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.

ITEM 16. *Form 10-K Summary*

Not applicable.

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: February 22, 2018

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)	February 22, 2018
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2018
/s/ WILLIAM M. BUERGLER **William M. Buergler**	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 22, 2018
/s/ R. BRAD MARTIN **R. Brad Martin**	Chairman of the Board	February 22, 2018
/s/ ARCHIE W. DUNHAM **Archie W. Dunham**	Director and Chairman Emeritus	February 22, 2018
/s/ GLORIA R. BOYLAND **Gloria R. Boyland**	Director	February 22, 2018
/s/ LUKE R. CORBETT **Luke R. Corbett**	Director	February 22, 2018
/s/ LESLIE S. KEATING **Leslie S. Keating**	Director	February 22, 2018
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	February 22, 2018
/s/ THOMAS L. RYAN **Thomas L. Ryan**	Director	February 22, 2018

Exhibit 10.9

EMPLOYMENT AGREEMENT

between

CHESAPEAKE ENERGY CORPORATION

and

Frank Patterson

Effective January 1, 2016

EMPLOYMENT AGREEMENT

THIS AGREEMENT is made effective January 1, 2016, between CHESAPEAKE ENERGY CORPORATION, an Oklahoma corporation (the "Company") and Frank Patterson, an individual (the "Executive").

W I T N E S S E T H:

WHEREAS, the Company desires to retain the services of the Executive and the Executive desires to make the Executive's services available to the Company.

NOW, THEREFORE, in consideration of the mutual promises herein contained, the Company and the Executive agree as follows:

1. Employment. The Company hereby employs the Executive and the Executive hereby accepts such employment subject to the terms and conditions contained in this Agreement. The Executive is engaged as an employee of the Company, and the Executive and the Company do not intend to create a joint venture, partnership or other relationship which might impose a fiduciary obligation on the Executive or the Company in the performance of this Agreement.

2. Executive's Duties. The Executive is employed on a full-time basis. Throughout the term of this Agreement, the Executive will use the Executive's best efforts and due diligence to assist the Company in achieving the most profitable operation of the Company and the Company's affiliated entities consistent with developing and maintaining a quality business operation. The Executive shall also devote all of Executive's working time, attention and energies to the performance of Executive's duties and responsibilities under this Agreement.

2.1 Specific Duties. The Executive will serve as EVP - Exploration for the Company, and in such other positions as might be mutually agreed upon by the parties. The Executive shall perform all of the duties required to fully and faithfully execute the office and position to which the Executive is appointed, and such other duties as may be reasonably requested by the Executive's supervisor or by the Company. During the term of this Agreement, the Executive may be nominated for election or appointed to serve as a director or officer of any of the Company's affiliated entities as determined in such affiliates' Board of Directors' sole discretion. The services of the Executive will be requested and directed by the Company's Chief Executive Officer, Robert D. Lawler.

2.2 Policies and Procedures. The Company has issued various policies and procedures applicable to all employees of the Company and its related and affiliated entities including an Employment Policies Manual which sets forth the general human resources policies of the Company and addresses frequently asked questions regarding the Company. The Executive agrees to comply with such policies and procedures except to the extent inconsistent with this Agreement. Such policies and procedures may be changed or adopted in the sole discretion of the Company without advance notice.

3. Other Activities. Except as provided in this Agreement or approved by the Compensation Committee, or its designee, as applicable, in writing, the Executive agrees not to: (a) engage in other operating business activities independent of the Company; (b) serve as a general partner, officer, executive, director or member of any corporation, partnership, company or firm; or (c) directly or indirectly invest, participate or engage in the Oil and Gas Business. For purposes of this Agreement the term "Oil and Gas Business" means: (i) producing oil and gas; (ii) drilling, owning or operating an interest in oil and gas leases or wells; (iii) providing material or services to the Oil and Gas Business; (iv) refining, processing, gathering, compressing, transporting or marketing oil or gas; or (v) owning an interest in or assisting any corporation, partnership, company, entity or person in any of the foregoing. The foregoing will not prohibit: (v) ownership of publicly traded securities; (w) ownership of royalty interests where the Executive owns or previously owned the surface of the land covered in whole or in part by the royalty interest and the ownership of the royalty interest is incidental to the ownership of such surface estate; (x) ownership of royalty interests, overriding royalty interests, working interests or other interests in oil and gas owned prior to the Executive's date of first employment with the Company and disclosed to the Company in writing; (y) ownership of royalty interests, overriding royalty interests, working interests or other interests in oil and gas acquired by the Executive through a bona fide gift or inheritance subject to disclosure by Executive to the Company in writing; or (z) service as an officer or director of a not-for-profit organization so long as such activity does not materially interfere with Executive's obligations under this Agreement. If the Executive serves as a director or officer of a not-for-profit organization, the Executive shall disclose the name of the organization and their involvement in an annual disclosure statement, the form of which shall be provided by the Company.

4. Executive's Compensation. The Company agrees to compensate the Executive as follows:

4.1 Base Salary. A base salary (the "Base Salary"), at the initial annual rate of not less than Six Hundred Thousand Dollars ($600,000) will be paid to the Executive in regular installments in accordance with the Company's designated payroll schedule.

4.2 Bonus. In addition to the Base Salary described in paragraph 4.1 of this Agreement, the Executive shall be eligible for an annual bonus for each fiscal year during the Term on the same basis as other executive officers under the Company's then current annual incentive plan with a target of 125% of Base Salary which shall be payable in accordance with the terms of such plan.

4.3 Equity Compensation. In addition to the compensation set forth in paragraphs 4.1 and 4.2 of this Agreement, the Executive will be eligible for annual grants of Chesapeake Energy Corporation restricted stock units, performance units, stock options or other awards from the Company's equity compensation plans with a target aggregate fair value of $2,500,000 (generally referred to as “Equity Compensation Plans”), subject to the terms and conditions of the Equity Compensation Plans.

4.4 Benefits. The Company will provide the Executive with benefits that are customarily provided to similarly situated executives of the Company and as are set forth in and governed by the Company's Employment Policies Manual and applicable plan documents. Additionally, the Company will provide paid time off (“PTO”) to the Executive, the amount of which will be determined in accordance with the Company’s PTO policy. No additional compensation will be paid for failure to take PTO. The Company will also provide the Executive the opportunity to apply for coverage under the Company's medical, life and disability plans, if any. If the Executive is accepted for coverage under such plans, the Company will make such coverage available to the Executive on the same terms as is customarily provided by the Company to the plan participants as modified from time to time in the Company’s sole discretion. Executive will be entitled to receive reimbursement for all reasonable business expenses incurred by Executive in accordance with the Company’s expense reimbursement policy. All payments for reimbursement under this Section 4.4 shall be paid promptly but in no event later than the last day of Executive’s taxable year following the taxable year in which Executive incurred such expenses.

5. Term. The term of Executive’s employment under the provisions of this Agreement shall be for a period commencing on the Effective Date and ending on December 31, 2018 (the "Term"); provided, however, if during the Term of this Agreement a Change of Control occurs, the Term of this Agreement shall be extended to the later of the original expiration date of the Term or the expiration of the Change of Control Period. For purposes of this Agreement, a "Change of Control" means the occurrence of any of the following:

(a) the acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of thirty percent (30%) or more of either (i) the then outstanding shares of Chesapeake Energy Corporation common stock (the "Outstanding CHK Common Stock") or (ii) the combined voting power of the then outstanding voting securities of Chesapeake Energy Corporation entitled to vote generally in the election of directors (the "Outstanding CHK Voting Securities"). For purposes of this paragraph, the following acquisitions by a Person will not constitute a Change of Control: (i) any acquisition by Chesapeake Energy Corporation; (ii) any redemption, share acquisition or other purchase of shares directly or indirectly by Chesapeake Energy Corporation; (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by Chesapeake Energy Corporation or any corporation controlled by Chesapeake Energy Corporation; or (iv) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of paragraph (c) below;

(b) during any period of not more than twenty-four (24) months, the individuals who constitute the Board of Directors (the "Incumbent Board") of Chesapeake Energy Corporation as of the beginning of the period cease for any reason to constitute at least a majority of the Board of Directors. Any individual becoming a director whose election, or nomination for election by Chesapeake Energy Corporation's shareholders, is approved by a vote of at least a majority of the directors then comprising the Incumbent Board will be considered a member of the Incumbent Board, but any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Incumbent Board will not be deemed a member of the Incumbent Board.

(c) the consummation of a reorganization, merger, consolidation or sale or other disposition of all or substantially all of the assets of Chesapeake Energy Corporation (a "Business Combination"), unless following such Business Combination: (i) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding CHK Common Stock and Outstanding CHK Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than sixty percent (60%) of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns Chesapeake Energy Corporation or all or substantially all of Chesapeake Energy Corporation's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding CHK Common Stock and Outstanding CHK Voting Securities, as the case may be, (ii) no Person (excluding any corporation resulting from such Business Combination or any employee benefit plan (or related trust) of Chesapeake Energy Corporation or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, thirty percent (30%) or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (iii) at least a majority of the members of the

Board of Directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Incumbent Board, providing for such Business Combination; or,

(d) the approval by the shareholders of Chesapeake Energy Corporation of a complete liquidation or dissolution of Chesapeake Energy Corporation.

For purposes of this Agreement, "Change of Control Period" means the twenty-four (24) month period commencing on the effective date of a Change of Control.

6. <u>Termination</u>. This Agreement will continue in effect until the expiration of the term stated in Section 5 of this Agreement unless earlier terminated pursuant to this Section 6. For purposes of this Agreement, "Termination Date" shall mean (a) if Executive's employment is terminated by death, the date of death; (b) if Executive's employment is terminated pursuant to Section 6.4 due to a disability, thirty (30) days after notice of termination is provided to Executive in accordance with Section 6.4; (c) if Executive's employment is terminated by Company without Cause or by Executive for Good Reason pursuant to Section 6.1.1 or 6.1.2, on the effective date of termination specified in the notice required by Section 6.1.1 or 6.1.2 respectively; (d) if Executive's employment is terminated by Company for Cause pursuant to Section 6.1.3, the date on which the notice of termination required by Section 6.1.3 is given; or (e) if Executive's employment is terminated by Executive pursuant to Section 6.2, on the effective date of termination specified by Executive in the notice of termination required by Section 6.2 unless the Company rejects such date as allowed by Section 6.2, in which case it would be the date specified by the Company.

6.1 <u>Termination by Company</u>. The Executive's employment under this Agreement may be terminated prior to the expiration of the Term under the following circumstances:

6.1.1 <u>Termination without Cause or for Good Reason Outside of a Change of Control Period</u>.

a) <u>Termination by the Company without Cause</u>. The Company may terminate the Executive's employment without Cause at any time by the service of written notice of termination to the Executive specifying an effective date of such termination not sooner than ten (10) days after the date of such notice. In lieu of the Executive working during this ten (10) day period, the Company may choose to end Executive's employment immediately by providing two (2) weeks of Base Salary.

b) <u>Termination by the Executive for Good Reason</u>. Executive may terminate employment with the Company for "Good Reason" and such termination will not be a breach of this

Agreement by Executive. For purposes of this paragraph 6.1.1(b), Good Reason shall mean the occurrence of one of the events set forth below:

(i) elimination of the Executive's job position or material reduction in duties and/or reassignment of the Executive to a new position of materially less authority; or

(ii) a material reduction in the Executive’s Base Salary.

Notwithstanding the foregoing, the Executive will not be deemed to have terminated for Good Reason unless (A) the Executive provides written notice to the Company of the existence of one of the conditions described above within ninety (90) days after the Executive has knowledge of the initial existence of the condition, (B) the Company fails to remedy the condition so identified within thirty (30) days after receipt of such notice (if capable of correction), (C) the Executive provides a notice of termination to the Company within thirty (30) days of the expiration of the Company’s period to remedy the condition specifying an effective date for the Executive’s termination, and (D) the effective date of the Executive’s termination of employment is within ninety (90) days after the Executive provides written notice to the Company of the existence of the condition referred to in clause (A).

c) Obligations of the Company. In the event the Executive is Terminated without Cause or terminates employment for Good Reason outside of a Change of Control Period, the Executive will receive as termination compensation within thirty (30) days of the Termination Date: (a) a payment of one (1) times the sum of Base Salary and Annual Bonus in a lump sum payment; (b) pro rata vesting through the last day of the month in which the Termination Date occurs of all unvested awards granted to Executive under the Equity Compensation Plans (provided performance share units shall only be payable subject to the attainment of the performance measures for the applicable performance period as provided under the terms of the applicable award agreement); (c) any Supplemental Matching Contributions to the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (the “401(k) Make-Up Plan”) shall be immediately vested; and (d) a lump sum payment of any PTO pay accrued but unused through the Termination Date. For purposes of this Agreement “Annual Bonus” shall be defined as the average of the annual bonus payments the Executive has received during the immediately preceding three (3) calendar years unless the Executive has been employed by the Company or held the position listed in section 2.1 for less than fifteen (15) months prior to the Termination Date, in which case, "Annual Bonus" shall be defined as the greater of (i) the Executive's target bonus for the year in which the Termination Date occurs or (ii) the average of the annual bonus payments the Executive has received during the immediately preceding three (3) calendar years. The right to the foregoing termination compensation described under clauses (a), (b) and (c) above is subject to the Executive's execution of the Company's severance agreement which will operate as a release of all legally waivable claims against the Company and the Executive's compliance with all of the provisions of this Agreement, including all post-employment obligations.

6.1.2 <u>Termination without Cause or for Good Reason During a Change of Control Period</u>.

(a) <u>Termination by the Company without Cause</u>. The Company may terminate the Executive's employment without Cause during a Change of Control Period at any time by the service of written notice of termination to the Executive specifying an effective date of such termination not sooner than ten (10) days after the date of such notice. In lieu of the Executive working during this ten (10) day period, the Company may choose to end Executive's employment immediately by providing two (2) weeks of Base Salary.

(b) <u>Termination by the Executive for Good Reason</u>. Executive may terminate employment with the Company for "Good Reason" and such termination will not be a breach of this Agreement by Executive. For purposes of this paragraph 6.1.2(b), Good Reason during a Change of Control Period shall mean the occurrence of one of the events set forth below:

(i) elimination of the Executive's job position or material reduction in duties and/or reassignment of the Executive to a new position of materially less authority;

(ii) a material reduction in Executive's Base Salary or

(iii) a requirement that the Executive relocate to a location outside of a fifty (50) mile radius of the location of his office or principal base of operation immediately prior to the effective date of a Change of Control.

Notwithstanding the foregoing, Executive will not be deemed to have terminated for Good Reason unless (A) Executive provides written notice to the Company of the existence of one of the conditions described above within ninety (90) days after Executive has knowledge of the initial existence of the condition, (B) the Company fails to remedy the condition so identified within thirty (30) days after receipt of such notice (if capable of correction), (C) Executive provides a Notice of Termination to the Company within thirty (30) days of the expiration of the Company's period to remedy the condition specifying an effective date for the Executive's termination, and (D) the effective date of the Executive's termination of employment is within ninety (90) days after Executive provides written notice to the Company of the existence of the condition referred to in clause (A).

(c) Obligations of the Company. In the event the Executive is Terminated without Cause or terminates employment for Good Reason during a Change of Control Period, the Executive will receive as termination compensation within thirty (30) days of the Termination Date: (a) a payment of two (2) times the sum of Base Salary and Annual Bonus in a lump sum payment; (b) all unvested awards granted under the Equity Compensation Plans shall be immediately vested (provided performance share units shall only be payable subject to the attainment of the performance measures for the applicable performance period as provided under the terms of the applicable award agreement); (c) any Supplemental Matching Contributions to the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (the "401(k) Make-Up Plan") shall be immediately vested; and (d) a lump sum payment of any PTO pay accrued but unused through the Termination Date. The right to the foregoing termination compensation described under clauses (a), (b) and (c) above is subject to the Executive's execution of the Company's severance agreement which will operate as a release of all legally waivable claims against the Company and the Executive's compliance with all of the provisions of this Agreement, including all post-employment obligations.

6.1.3 Termination for Cause. The Company may terminate the employment of the Executive hereunder at any time for Cause (as hereinafter defined) (such a termination being referred to in this Agreement as a "Termination For Cause") by giving the Executive written notice of such termination. As used in this Agreement, "Cause" means:

(i) the willful and continued failure of the Executive to perform substantially the Executive's duties with the Company or one of its affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive by the Board or the Chief Executive Officer of the Company which specifically identifies the manner in which the Board or Chief Executive Officer believes that the Executive has not substantially performed the Executive's duties, or

(ii) the willful engaging by the Executive in illegal conduct or gross misconduct which is materially and demonstrably injurious to the Company. For purposes of this provision, no act, or failure to act, on the part of the Executive shall be considered "willful" unless it is done, or omitted to be done, by the Executive in bad faith or without reasonable belief that the Executive's action or omission was in the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the instructions of the Chief Executive Officer or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by the Executive in good faith and in the best interests of the Company.

In the event this Agreement is terminated for Cause, the Company will not have any obligation to provide any further payments or benefits to the Executive after the Termination Date other than a lump sum payment within thirty (30) days of the Termination Date of any PTO pay accrued but unused through the Termination Date.

6.2 Termination by Executive. The Executive may voluntarily terminate employment under this Agreement for any reason by the service of written notice of such termination to the Company specifying an effective date of termination no sooner than thirty (30) days and no later than sixty (60) days after the date of such notice; provided, however, if less than thirty (30) days remain in the Term, the minimum notice required from Executive under this Section 6.2 shall be reduced from thirty (30) to seven (7) days. The Company reserves the right to end the employment relationship at any time after the date such notice is given to the Company and to pay Executive through the Termination Date.

6.3 Retirement by Executive. In the event the Executive is fifty-five (55) years or older and the Executive's employment is terminated under Sections 6.1.1 or 6.2 of this Agreement, the Executive will be (a) eligible for continued post-retirement vesting of the unvested awards granted under the Equity Compensation Plans (provided performance share units shall only be payable subject to the attainment of the performance measures for the applicable performance period as provided under the terms of the applicable award agreement); and (b) eligible for accelerated vesting of the unvested Supplemental Matching Contributions to the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (the "401(k) Make-Up Plan"). The vesting under clauses (a) and (b) of this Section 6.3 will be in accordance with the retirement matrix (the "Retirement Matrix") attached to this Agreement. The right to acceleration and continued vesting is subject to the Executive's execution of the Company's severance agreement which will include a release of all legally waivable claims between the parties as of the effective date of the release except for the Company's obligation to pay the foregoing severance compensation and the Executive's obligation to comply with all post-employment obligations under this Agreement.

6.4 Disability. If the Executive suffers from a physical or mental condition which in the reasonable judgment of the Company's management prevents the Executive from being able to perform the duties specified herein for a period of twelve (12) consecutive weeks, the Executive may be terminated by the Company. In the event the Executive is terminated due to Disability (a) all unvested awards granted to the Executive under the Equity Compensation Plans shall be immediately vested (provided performance share units shall only be payable subject to the attainment of the performance measures for the applicable performance period as provided under the terms of the applicable award agreement); and (b) any Supplemental Matching Contributions to the Chesapeake Energy 401(k) Make-Up Plan shall be immediately vested. Executive shall also receive a lump sum payment within thirty (30) days of the Termination Date of any PTO pay accrued but unused through the Termination Date. The right to the foregoing compensation due under clauses (a) and (b) above is subject to the execution by the Executive or the Executive's legal representative of the Company's severance agreement which will operate as a release of all legally waivable claims against the Company. In applying this Section 6.4, the Company will comply with any applicable legal requirements, including the Americans with Disabilities Act.

6.5 Death of Executive. If the Executive dies during the term of this Agreement, the Company may thereafter terminate this Agreement without compensation. In the event of the Executive's death the Company will (a) immediately vest all unvested awards granted to the Executive under the Equity Compensation Plans (provided performance share units shall only be payable subject to the attainment of the performance measures for the applicable performance period as provided under the terms of the applicable award agreement); and (b) immediately vest any Supplemental Matching Contributions to the Chesapeake Energy 401(k) Make-Up Plan. Executive's beneficiaries/estate shall also receive a lump sum payment within thirty (30) days of death of any PTO pay accrued but unused through the Termination Date. Amounts payable under this Section 6.5 shall be paid to the beneficiary designated on the Company's universal beneficiary designation form in effect on the date of the Executive's death. If the Executive fails to designate a beneficiary or if such designation is ineffective, in whole or in part, any payment that would otherwise have been paid under this Section 6.5 shall be paid to the Executive's estate. The right to the foregoing compensation due under clauses (a) and (b) above is subject to the execution by the beneficiary, or as applicable, the administrator of the Executive's estate of the Company's severance agreement which will operate as a release of all legally waivable claims against the Company.

6.6 Effect of Termination. The termination of this Agreement, when accompanied by the termination of Executive’s employment with the Company, will terminate all obligations of the Executive to render services on behalf of the Company from and after the Termination Date, provided that upon termination of this Agreement and termination of employment for any reason (other than by reason of Executive’s death), the Executive will maintain the confidentiality of all information acquired by the Executive during the term of Executive's employment in accordance with the terms and provisions of the Company’s Confidentiality Agreement and the Executive shall comply with all other post employment requirements including Section 6.6 and Sections 7, 8, 9, 10, 11, 12 and 13 as well as the Company’s arbitration program. Except as otherwise provided in Sections 4.5 and 6 of this Agreement and payment of any PTO pay accrued but unused through the Termination Date, no accrued bonus, severance pay or other form of compensation will be payable by the Company to the Executive by reason of the termination of this Agreement. All keys, entry cards, credit cards, files, records, financial information, Confidential Information, research, results, test data, instructions, drawings, sketches, specifications, product data sheets, products, books, DVDs, disks, memory devices, business plans, marketing plans, documents, correspondence, furniture, furnishings, equipment, supplies and other items relating to the Company in the Executive's possession will remain the property of the Company. Upon termination of employment, the Executive will have the right to retain and remove all personal property and effects which are owned by the Executive and located in the offices of the Company at a time determined by the Company. All such personal items will be removed from such offices no later than two (2) days after the Termination Date, and the Company is hereby authorized to discard any items remaining and to reassign the Executive's office space after such date. Prior to the Termination Date, the Executive will render such services to the Company as might be reasonably required to provide for the orderly termination of the Executive's employment. Notwithstanding the foregoing and without discharging any obligations to pay compensation to the Executive under this Agreement, after notice of the termination, the Company may request that the Executive not provide any other services to the Company and not enter the Company's premises before or after the Termination Date. In the event that the Executive separates employment with the Company, Executive hereby grants consent to notification by the Company to Executive's new employer about Executive's rights and obligations under this Agreement. Upon such termination of employment, the Executive further agrees to acknowledge compliance with this Agreement in a form reasonably provided by the Company.

If this Agreement is not terminated pursuant to any of the preceding provisions of Section 6 or extended by mutual written agreement of the parties prior to the expiration of the Term, this Agreement and Executive’s employment under this Agreement will end and Company will have no further obligation to provide any further payments or benefits to Executive under this Agreement after the expiration of the Term other than any PTO pay accrued but unused through the expiration of the Term. Upon expiration of this Agreement, Executive will continue to be employed with Company on an at will basis until such employment is terminated by either party, with or without any reason.

7. Non-Competition. For a period of one (1) year after the Executive is no longer employed by the Company for any reason, the Executive will not knowingly acquire, attempt to acquire or aid another in the acquisition or attempted acquisition of an interest in oil and gas assets, oil and gas production, oil and gas leases, mineral interests, oil and gas wells or other such oil and gas exploration, development or production activities within any spacing unit in which the Company owns an oil and gas interest on the date of the resignation or termination of the Executive.

8. Non-Solicitation. The Executive agrees that during his employment hereunder, and for the one (1) year period immediately following termination of employment for any reason, the Executive shall not solicit or contact any established customer of the Company with a view to inducing or encouraging such established client or customer to discontinue or curtail any business relationship with the Company. The Executive further agrees that the Executive will not request or advise any established customers of the Company to withdraw, curtail or cancel its business with the Company.

9. Non-Solicitation of Employees. The Executive covenants that during the term of employment and for the one (1) year period immediately following the termination of employment for any reason, Executive will neither directly nor indirectly induce nor attempt to induce any executive or employee of the Company to terminate his/her employment with the Company to go to work for any other company or third party.

10. Reasonableness. The Company and the Executive have attempted to specify a reasonable period of time and reasonable restrictions to which this Agreement shall apply. The Company and Executive agree that if a court or administrative body should subsequently determine that the terms of this Agreement are greater than reasonably necessary to protect the Company's interest, the Company agrees to

waive those terms which are found by a court or administrative body to be greater than reasonably necessary to protect the Company's interest and to request that the court or administrative body reform this Agreement specifying a reasonable period of time and such other reasonable restrictions as the court or administrative body deems necessary.

11. Equitable Relief. The Executive acknowledges that the services to be rendered by Executive are of a special, unique, unusual, extraordinary, and intellectual character, which gives them a peculiar value, and the loss of which cannot reasonably or adequately be compensated in damages in an action at law; and that a breach by the Executive of any of the provisions contained in this Agreement will cause the Company irreparable injury and damage. The Executive further acknowledges that the Executive possesses unique skills, knowledge and ability and that any material breach of the provisions of this Agreement would be extremely detrimental to the Company. By reason thereof, the Executive agrees that the Company shall be entitled, in addition to any other remedies it may have under this Agreement or otherwise, to injunctive and other equitable relief to prevent or curtail any breach of this Agreement by him/her.

12. Continued Litigation Assistance. The Executive will cooperate with and assist the Company and its representatives and attorneys as requested, during and after the Term, with respect to any litigation, arbitration or other dispute resolutions by being available for interviews, depositions and/or testimony in regard to any matters in which the Executive is or has been involved or with respect to which the Executive has relevant information. The Company will reimburse the Executive for any reasonable business expenses the Executive may have incurred in connection with this obligation.

13. Arbitration Any disputes, claims or controversies between the Company and Executive including, but not limited to those arising out of or related to this Agreement or out of the parties' employment relationship (together, “Employment Matter”), shall be settled by arbitration as provided herein. This agreement shall survive the termination or rescission of this Agreement. All arbitration shall be in accordance with Rules of the American Arbitration Association, including discovery, and shall be undertaken pursuant to the Federal Arbitration Act. Arbitration will be held in Oklahoma City, Oklahoma unless the parties mutually agree to another location. The decision of the arbitrator will be enforceable in any court of competent jurisdiction. Executive and the Company agree that either party shall be entitled to obtain injunctive or other equitable relief to enforce the provisions of this Agreement in a court of competent jurisdiction. The parties further agree that this arbitration provision is not only applicable to the Company but its affiliates, officers, directors, employees and related parties. Executive agrees that he shall have no right or authority for any dispute to be brought, heard or arbitrated as a class or collective action, or in a representative or a private attorney general capacity on behalf of a class of persons or the general public. No class, collective or representative actions are thus allowed to be arbitrated Executive agrees that he must pursue any claims that he may have solely on an individual basis through arbitration.

14. Miscellaneous. The parties further agree as follows:

14.1 Time. Time is of the essence of each provision of this Agreement.

14.2 Notices. Any notice, payment, demand or communication required or permitted to be given by any provision of this Agreement will be in writing and will be deemed to have been given when delivered personally or by express mail to the party designated to receive such notice, or on the date following the day sent by overnight courier, or on the third business day after the same is sent by certified mail, postage and charges prepaid, directed to the following address or to such other or additional addresses as any party might designate by written notice to the other party:

To the Company:	Chesapeake Energy Corporation 6100 N. Western Ave. Oklahoma City, OK 73118 Attn: James L. Hawkins
To the Executive:	The most recent home address reflected in the records of the Company.

14.3 Assignment. Neither this Agreement nor any of the parties' rights or obligations hereunder can be transferred or assigned without the prior written consent of the other parties to this Agreement; provided, however, the Company may assign this Agreement to any wholly owned affiliate or subsidiary of Chesapeake Energy Corporation without Executive's consent as well as to any purchaser of the Company.

14.4 Construction. If any provision of this Agreement or the application thereof to any person or circumstances is determined, to any extent, to be invalid or unenforceable, the remainder of this Agreement, or the application of such provision to persons or circumstances other than those as to which the same is held invalid or unenforceable, will not be affected thereby, and each term and provision of this Agreement will be valid and enforceable to the fullest extent permitted by law. Except as provided for in Section 13, this Agreement is intended to be interpreted, construed and enforced in accordance with the laws of the State of Oklahoma.

14.5 Entire Agreement. This Agreement, any documents executed in connection with this Agreement, any documents specifically referred to in this Agreement and the Employment Policies Manual constitute the entire agreement between the parties hereto with respect to the subject matter herein contained, and no modification hereof will be effective unless made by a supplemental written agreement executed by all of the parties hereto.

14.6 Binding Effect. This Agreement will be binding on the parties and their respective successors, legal representatives and permitted assigns. In the event of a merger, consolidation, combination, dissolution or liquidation of the Company, the performance of this Agreement will be assumed by any entity which succeeds to or is transferred the business of the Company as a result thereof, and the Executive waives the consent requirement of Section 14.3 to effect such assumption.

14.7 Supersession. On execution of this Agreement by the Company and the Executive, the relationship between the Company and the Executive will be bound by the terms of this Agreement, any documents executed in connection with this Agreement, any documents specifically referred to in this Agreement and the Employment Policies Manual as well as any other agreements executed in connection with Executive's employment with the Company. In the event of a conflict between the Employment Policies Manual and this Agreement, this Agreement will control in all respects.

14.8 Third-Party Beneficiary. The Company's affiliated entities and partnerships are beneficiaries of all terms and provisions of this Agreement and entitled to all rights hereunder.

14.9 Section 409A. This Agreement is intended to be exempt from Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), and related U.S. Treasury regulations or official pronouncements ("Section 409A") and any ambiguous provision will be construed in a manner that is compliant with such exemption; provided, however, if and to the extent that any compensation payable pursuant to this Agreement is determined to be subject to Section 409A, this Agreement will be construed in a manner that will comply with Section 409A. Notwithstanding any provision to the contrary in this Agreement, if the Executive is deemed on his Termination Date to be a "specified employee" within the meaning of that term under Section 409A, then any payments and benefits under this Agreement that are subject to Section 409A and paid by reason of a termination of employment shall be made or provided on the later of (a) the payment date set forth in this Agreement or (b) the date that is the earliest of (i) the expiration of the six-month period measured from the date of the Executive's termination of employment or (ii) the date of the Executive's death (the "Delay Period"). Payments and benefits subject to the Delay Period shall be paid or provided to the Executive without interest for such delay. Termination of employment as used throughout this Agreement shall refer to a separation from service within the meaning of Section 409A. To the extent required to comply with Section 409A, references to a "resignation," "termination," "termination of employment" or like terms throughout this Agreement shall be interpreted consistent with the meaning of "separation from service" as defined in Section 409A.

14.10 Dodd-Frank Act. Notwithstanding anything in this Agreement or any other agreement between the Company and/or its related entities and Executive to the contrary, Executive acknowledges that the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Act") may have the effect of requiring certain executives of the Company and/or its related entities to repay the Company, and for the Company to recoup from such executives, certain amounts of incentive-based compensation. If, and only to the extent, the Act, any rules and regulations promulgated by thereunder by the Securities and Exchange Commission or any similar federal or state law requires the Company to recoup incentive-based compensation that the Company has paid or granted to Executive, Executive hereby agrees, even if Executive has terminated his employment with the Company, to promptly repay such incentive compensation to the Company upon its written request. This Section shall survive the termination of this Agreement.

14.11 Maximum Payments by the Company.

(a) It is the objective of this Agreement to maximize Executive's Net After-Tax Benefit (as defined herein) if payments or benefits provided under this Agreement are subject to excise tax under Section 4999 of the Code. Notwithstanding any other provisions of this Agreement, in the event that any payment or benefit by the Company or otherwise to or for the benefit of Executive, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise, including, by example and not by way of limitation, acceleration by the Company or otherwise of the date of vesting or payment or rate of payment under any plan, program, arrangement or agreement of the Company (all such payments and benefits, including the payments and benefits under Section 6 hereof, being hereinafter referred to as the "Total Payments"), would be subject (in whole or in part) to the excise tax imposed by Section 4999 of the Code (the "Excise Tax"), then the cash severance payments shall first be reduced, and the non-cash severance payments shall thereafter be reduced, to the extent necessary so that no portion of the Total Payments shall be subject to the Excise Tax, but only if (i) the net amount of such Total Payments, as so reduced (and after subtracting the net amount of federal, state and local income taxes on such reduced Total Payments and after taking into account the phase out of itemized deductions and personal exemptions attributable to such reduced Total Payments), is greater than or equal to (ii) the net amount of such Total Payments without such reduction (but after subtracting the net amount of federal, state and local income taxes on such Total Payments and the amount of Excise Tax to which Executive would be subject in respect of such unreduced Total Payments and after taking into account the phase out of itemized deductions and personal exemptions attributable to such unreduced Total Payments).

(b) The Total Payments shall be reduced by the Company in the following order: (i) reduction of any cash severance payments otherwise payable to Executive that are exempt from Section 409A of the Code, (ii) reduction of any other cash payments or benefits otherwise payable to Executive that are exempt from Section 409A of the Code, but excluding any payments attributable to the acceleration of vesting or payments with respect to any equity award with respect to the Company's common stock that is exempt from Section 409A of the Code, (iii) reduction of any other payments or benefits otherwise payable to Executive on a pro-rata basis or such other manner that complies with Section 409A of the Code, but excluding any payments attributable to the acceleration of vesting and payments with respect to any equity award with respect to the Company's common stock that are exempt from Section 409A of the Code, and (iv) reduction of any payments attributable to the acceleration of vesting or payments with respect to any other equity award with respect to the Company's common stock that are exempt from Section 409A of the Code.

(c) For purposes of determining whether and the extent to which the Total Payments will be subject to the Excise Tax, (i) no portion of the Total Payments the receipt or enjoyment of which Executive shall have waived at such time and in such manner as not to constitute a "payment" within the meaning of Section 280G(b) of the Code shall be taken into account, (ii) no portion of the Total Payments shall be taken into account which, in the written opinion of independent auditors of nationally recognized standing ("Independent Advisors") selected by the Company, does not constitute a "parachute payment" within the meaning of Section 280G(b)(2) of the Code (including by reason of Section 280G(b)(4)(A) of the Code) and, in calculating the Excise Tax, no portion of such Total Payments shall be taken into account which, in the opinion of Independent Advisors, constitutes reasonable compensation for services actually rendered, within the meaning of Section 280G(b)(4)(B) of the Code, in excess of the "base amount" (as defined in Section 280G(b)(3) of the Code) allocable to such reasonable compensation, and (iii) the value of any non-cash benefit or any deferred payment or benefit included in the Total Payments shall be determined by the Independent Advisors in accordance with the principles of Sections 280G(d)(3) and (4) of the Code. The costs of obtaining such determination shall be borne by the Company.

IN WITNESS WHEREOF, the undersigned have executed this Agreement effective the date first above written.

CHESAPEAKE ENERGY CORPORATION, an Oklahoma corporation

By: /s/ Robert D. Lawler

Robert D. Lawler, Chief Executive Officer
(the "Company")

By: /s/ Frank Patterson

Frank Patterson, Individually
(the "Executive")

RETIREMENT MATRIX

Service Yrs	<55	55-59	60-64	>=65
0-5	0%	0%	0%	0%
5-10	0%	60%	80%	100%
10-15	0%	80%	100%	100%
15-20	0%	100%	100%	100%
20+	0%	100%	100%	100%

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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

	Years Ended December 31,				
	2013	2014	2015	2016	2017
EARNINGS:					
Income (loss) before income taxes and cumulative effect of accounting change	$ 1,442	$ 3,200	$ (19,098)	$ (4,589)	$ 954
Interest expense[a]	207	172	322	275	421
Loss on investment in equity investees in excess of distributed earnings	219	75	96	8	—
Amortization of capitalized interest	440	438	483	729	487
Loan cost amortization	37	32	31	24	25
Less: (Income) loss attributable to noncontrolling interests			68	9	(4)
Earnings (losses)	$ 2,345	$ 3,917	$ (18,098)	$ (3,544)	$ 1,883
FIXED CHARGES:					
Interest Expense	$ 207	$ 172	$ 322	$ 275	$ 421
Capitalized interest	815	604	410	242	193
Loan cost amortization	37	32	31	24	25
Fixed Charges	$ 1,059	$ 808	$ 763	$ 541	$ 639
PREFERRED STOCK DIVIDENDS:					
Preferred dividend requirements	$ 171	$ 171	$ 171	$ 97	$ 84
Ratio of income (loss) before provision for taxes to net income (loss)[b]	1.61	1.56	1.30	1.04	1.00
Preferred Dividends	$ 275	$ 266	$ 222	$ 101	$ 84
COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS	$ 1,334	$ 1,074	$ 985	$ 642	$ 723
RATIO OF EARNINGS TO FIXED CHARGES	2.2	4.8	(23.7)	(6.6)	2.9
INSUFFICIENT COVERAGE	$ —	$ —	$ 18,861	$ 4,085	$ —
RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS	1.8	3.6	(18.4)	(5.5)	2.6
INSUFFICIENT COVERAGE	$ —	$ —	$ 19,083	$ 4,186	$ —

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

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

CHESAPEAKE ENERGY CORPORATION
an Oklahoma Corporation

SIGNIFICANT SUBSIDIARIES*

Limited Liability Companies	State of Organization
Chesapeake Appalachia, L.L.C.	Oklahoma
Chesapeake E&P Holding, L.L.C.	Oklahoma
Chesapeake Energy Marketing, L.L.C.	Oklahoma
Chesapeake Exploration, L.L.C.	Oklahoma
Chesapeake Land Development Company, L.L.C.	Oklahoma
Chesapeake Operating, L.L.C.	Oklahoma

* In accordance with Regulation S-K Item 601(b)(21), the names of particular subsidiaries that, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary (as that term is defined in Rule 1-02(w) of Regulation S-X) as of the end of the year covered by this report have been omitted.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 333-126191, 333-135949, 333-143990, 333-151762, 333-160350, 333-171468, 333-178067, 333-187018, 333-189651, 333-192175, 333-196977 and 333-214683) and Form S-3 (File No. 333-219649) of Chesapeake Energy Corporation of our report dated February 22, 2018 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 22, 2018

Exhibit 23.2

Software Integrated Solutions
Division of Schlumberger Technology Corporation

4600 J Barry Court
Suite 200
Canonsburg, PA 15317 USA
Tel: 724-416-9700
Fax: 724-416-9705

Schlumberger

CONSENT OF SOFTWARE INTEGRATED SOLUTIONS
DIVISION OF SCHLUMBERGER TECHNOLOGY CORPORATION

As independent oil and gas consultants, Software Integrated Solutions, Division of Schlumberger Technology Corporation hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 333-126191, 333-135949, 333-143990, 333-151762, 333-160350, 333-171468, 333-178067, 333-187018, 333-189651, 333-192175, 333-196977 and 333-214683) and Form S-3 (File No. 333-219649)of Chesapeake Energy Corporation of all references to our firm and information from our reserves report dated 30 January 2018, included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended 31 December 2017 to be filed with the Securities and Exchange Commission on or about 22 February 2018, and our summary report attached as Exhibit 99 to such Annual Report.

Software Integrated Solutions
Division of Schlumberger Technology Corporation

By:
Charles M. Boyer II, PG, CPG
Advisor - Unconventional Reservoirs
Technical Team Leader

Canonsburg, Pennsylvania
22 February, 2018

Exhibit 31.1

CERTIFICATION

I, Robert D. Lawler, certify that:

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

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

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

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

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

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

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

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

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

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

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

February 22, 2018

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

Exhibit 31.2

CERTIFICATION

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

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

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

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

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

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

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

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

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

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

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

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

February 22, 2018	By:	/s/ DOMENIC J. DELL’OSSO, JR.
		Domenic J. Dell’Osso, Jr.
		Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Chesapeake Energy Corporation (the “Company”) on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert D. Lawler, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

February 22, 2018

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

Exhibit 32.2

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

In connection with the Annual Report of Chesapeake Energy Corporation (the “Company”) on Form 10-K for the year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Domenic J. Dell’Osso, Jr., Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

February 22, 2018	By:	/s/ DOMENIC J. DELL’OSSO, JR.
		Domenic J. Dell’Osso, Jr.
		Executive Vice President and Chief Financial Officer

Software Integrated Solutions
Division of Schlumberger Technology Corporation

4600 J. Barry Court
Suite 200
Canonsburg, Pennsylvania 15317 USA
Tel: +1-724-416-9700
Fax: +1-724-416-9705

30 January 2018

Chesapeake Energy Corporation
6100 N. Western Avenue
Oklahoma City, OK 73118

Dear Gentlemen:

At the request of Chesapeake Energy Corporation (Chesapeake), through their letter of engagement, Software Integrated Solutions (SIS) Division of Schlumberger Technology Corporation has evaluated the proved reserves of certain Chesapeake oil and gas interests located in the United States (U.S.) as of 31 December 2017. The evaluated properties are located in Louisiana, Ohio, Oklahoma, Pennsylvania, Texas, and Wyoming. This report was completed as of the date of this letter and has been prepared using constant prices and costs and conforms to our understanding of the U.S. Securities and Exchange Commission (SEC) guidelines and applicable financial accounting rules. All prices, costs, and cash flow estimates are expressed in U.S. dollars (US$). It is our understanding that the total proved properties evaluated by SIS comprise approximately 83.2% of Chesapeake's reserves and 87.7% of the Discounted Present Value @10%. We prepared this report for Chesapeake's use in filing with the SEC. We believe that the assumptions, data, methods, and procedures used in preparing this report are appropriate for the purpose of this report and that we have used all methods and procedures that we consider necessary and appropriate under the circumstances to prepare this report. The Lead Evaluator for this evaluation was Charles M. Boyer II, PG, CPG, and his qualifications, independence, objectivity, and confidentiality meet the requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The results of the Proved reserve evaluation are summarized in **Table 1** and **Table 2**. The values contained in this report do not include existing Chesapeake financial instruments or hedges.

Table 1
Estimated Net Reserves And Income
Certain Oil And Gas Interests
Chesapeake Energy Corporation
As Of 31 December 2017
Proved Developed And Undeveloped Reserves

	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Remaining Net Reserves			
Oil - Mbbls	115,848.81	73,295.52	189,144.33
NGL - Mbbls	112,539.12	67,687.46	180,226.58
Gas - MMscf	4,076,415.93	3,254,330.40	7,330,746.33
Oil Equiv. - Mbbls	907,790.59	683,371.38	1,591,161.96
Income Data (M$)			
Future Net Revenue	12,225,487.87	8,869,471.24	21,094,959.12
Deductions			
Operating Expense	2,602,089.28	1,003,962.17	3,606,051.45
Production Taxes	742,863.15	511,634.22	1,254,497.37
Abandonment Expense	182,584.90	48,354.32	230,939.23
Investment	154,273.95	3,321,419.38	3,475,693.33
Future Net Cashflow (FNC)	8,543,676.73	3,984,101.25	12,527,777.98
Discounted PV @ 10% (M$)	5,051,211.66	1,515,755.55	6,566,967.21

Table 2
Estimated Net Reserves And Income
Certain Oil And Gas Interests
Summarized By Reserve Category
Chesapeake Energy Corporation
As Of 31 December 2017

	Proved Producing Reserves	Proved NonProducing Reserves	Proved Shut-In Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Remaining Net Reserves					
Oil - Mbbls	109,441.25	6,407.55	0.00	73,295.52	189,144.33
NGL - Mbbls	112,462.22	76.90	0.00	67,687.46	180,226.58
Gas - MMscf	3,764,714.61	311,701.33	0.00	3,254,330.40	7,330,746.33
Oil Equiv. - Mbbls	849,355.91	58,434.67	0.00	683,371.38	1,591,161.96
Income Data (M$)					
Future Net Revenue	11,505,341.02	720,146.85	0.00	8,869,471.24	21,094,959.12
Deductions					
Operating Expense	2,514,078.79	87,986.09	24.40	1,003,962.17	3,606,051.45
Production Taxes	712,291.42	30,571.73	0.00	511,634.22	1,254,497.37
Abandonment Expense	175,455.16	6,873.69	256.05	48,354.32	230,939.23
Investment	0.00	154,273.95	0.00	3,321,419.38	3,475,693.33
Future Net Cashflow (FNC)	8,103,515.77	440,441.41	(280.45)	3,984,101.25	12,527,777.98
Discounted PV @ 10% (M$)	4,782,382.19	268,951.71	(122.24)	1,515,755.55	6,566,967.21

The values in the tables above may not add up arithmetically due to rounding procedures in the computer software program used to prepare the economic projections. All hydrocarbon liquids are reported as 42 gallon barrels. Gas volumes are reported at the standard pressure and temperature bases of the area where the gas is sold.

We are independent with respect to Chesapeake as provided in the SEC regulations. Neither the employment of nor the compensation received by SIS was contingent upon the values estimated for the properties included in this report.

Oil and gas reserves by definition fall into one of the following categories: proved, probable, and possible. The proved category is further divided into: developed and undeveloped. The developed reserve category is even further divided into the appropriate reserve status subcategories: producing and non-producing. Non-producing reserves include shut-in and behind-pipe reserves. The reserves included in this report include only proved reserves and do not include probable or possible reserves. Chesapeake has an active exploration and development program to develop their interests in certain tracts not classified as proved at this time. Future drilling may result in the reclassification of additional volumes to the proved reserve category. However, changes in the regulatory requirements for oil and gas operations may impact future development plans and the ability of the company to recover the estimated proved undeveloped reserves. The reserves and income attributable to the various reserve categories included in this report have not been adjusted to reflect the varying degrees of risk associated with them.

Reserve estimates are strictly technical judgments. The accuracy of any reserve estimate is a function of the quality and quantity of data available and of the engineering and geological interpretations. The reserve estimates presented in this report are believed reasonable; however, they are estimates only and should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify their revision. A portion of these reserves are for producing or non-producing wells that lack sufficient production history to utilize conventional performance-based reserve estimates. In these

cases, the reserves are based on volumetric estimates and recovery efficiencies along with analogies to similar producing areas. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. As additional production and pressure data becomes available, these estimates may be revised up or down. Actual future prices may vary significantly from the prices used in this evaluation; therefore, future hydrocarbon volumes recovered and the income received from these volumes may vary significantly from those estimated in this report. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

Standard geological and engineering methods generally accepted by the petroleum industry were used in the estimation of Chesapeake's reserves. Deterministic methods were used for all reserves included in this report. The appropriate combination of conventional decline curve analysis (DCA), production data analysis, volumetrics, reservoir simulation, and type curves were used to estimate the remaining reserves in the various producing areas. Volumetric calculations were based on data and maps provided by Chesapeake. Comparisons were made to similar properties for which more complete data were available for areas of new development.

All prices used in preparation of this report were based on the twelve month unweighted arithmetic average of the first day of the month price for the period January through December 2017. The resulting Henry Hub reference gas price used was $2.98/MMBtu and the resulting West Texas Intermediate reference oil price used was $51.34/Bbl. Henry Hub gas price and West Texas Intermediate oil price are common reference prices for natural gas and oil production in the U.S. The prices were adjusted for local differentials, gravity and Btu where applicable. As required by SEC guidelines, all pricing was held constant for the life of the projects (no escalation). **Table 3** summarizes the 2017 reference prices and the resulting average prices used in this reserves evaluation. The average prices were calculated using the total future revenue by product prior to taxes and expenses divided by the total net reserves by product.

Table 3
Chesapeake Energy Corporation
Oil, Gas And NGL Prices
Year End 2017 Reserves Evaluation

Product	Reference Point	Year End 2017 Reference Price	Average Price
Oil	West Texas Intermediate	$51.34/Bbl	$46.59/Bbl
NGL	West Texas Intermediate	$51.34/Bbl	$14.73/Bbl
Natural Gas	Henry Hub	$2.98/MMBtu	$1.31/Mscf

Operating costs used in this report were based on values reported by Chesapeake and reviewed by SIS. Operating cost assumptions were based on the prior twelve months average data. Chesapeake's estimates for capital costs for all non-producing and undeveloped wells are included in the evaluation. Abandonment and salvage were included as expenses 120 months after the economic limit is reached. Chesapeake has indicated to us that they have the ability and intent to implement their capital expenditure program as scheduled. Operating costs and capital costs were held constant for the life of the projects (no escalation).

Net revenue (sales) is defined as the total proceeds from the sale of oil, condensate, natural gas liquids (NGL), and gas adjusted for commodity price basis differential and gathering/ transportation expense. Future net income (cashflow) is future net revenue less net lease operating expenses, state severance or production taxes, certain allowed corporate general administrative and overhead costs, operating/development capital expenses and net salvage. Future plugging, abandonment, and salvage costs are included after the economic life of each well or unit. No provisions for State or Federal income taxes have been made in this evaluation. The present worth (discounted cashflow) at various discount rates is calculated on a monthly basis.

In the conduct of our evaluation, we have not independently verified the accuracy and completeness of information and data furnished by Chesapeake with respect to ownership interests, historical oil and gas production, costs of operation and development, product prices, payout balances, and agreements relating to current and future operations and sales of production. If in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of the information or data provided by Chesapeake, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

In our opinion the above-described estimates of Chesapeake's proved reserves and supporting data are, in the aggregate, reasonable. It is also our opinion that the above-described estimates of Chesapeake's proved reserves conform to the definitions of proved oil and gas reserves promulgated by the Securities and Exchange Commission. These reserves definitions are provided at the conclusion of this letter.

All data used in this study were obtained from Chesapeake, public industry information sources, or the non-confidential files of SIS. A field inspection of the properties was not made in connection with the preparation of this report. The potential environmental liabilities attendant to ownership and/or operation of the properties have not been addressed in this report. Abandonment and clean-up costs and possible salvage value of the equipment were considered in this report.

In evaluating the information at our disposal related to this report, we have excluded from our consideration all matters which require a legal or accounting interpretation, or any interpretation other than those of an engineering or geological nature. In assessing the conclusions expressed in this report pertaining to all aspects of oil and gas evaluations, especially pertaining to reserve evaluations, there are uncertainties inherent in the interpretation of engineering data, and such conclusions represent only informed professional judgments.

Data and worksheets used in the preparation of this evaluation will be maintained in our files in Canonsburg and will be available for inspection by anyone having proper authorization from Chesapeake.

Sincerely yours,

/s/ Denise L. Delozier

Denise L. Delozier
Principal Reservoir Engineer

/s/ Charles M. Boyer II

Charles M. Boyer II, PG, CPG
Advisor - Unconventional Reservoirs
Technical Team Leader

SECURITIES AND EXCHANGE COMMISION
REGULATION S-X, RULE 210.4-10 (a)

RESERVES DEFINITIONS

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) 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; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or *G&G* costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is 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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.* (i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(*1*) Lifting the oil and gas to the surface; and

(*2*) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a “terminal point”, which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.* (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) 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 gas on the basis of available geoscience and engineering data.

(ii) 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.

(iii) 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.

(iv) 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:

(A) 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

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be 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 such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if not drilled in a known area or “development type” if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be 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.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.