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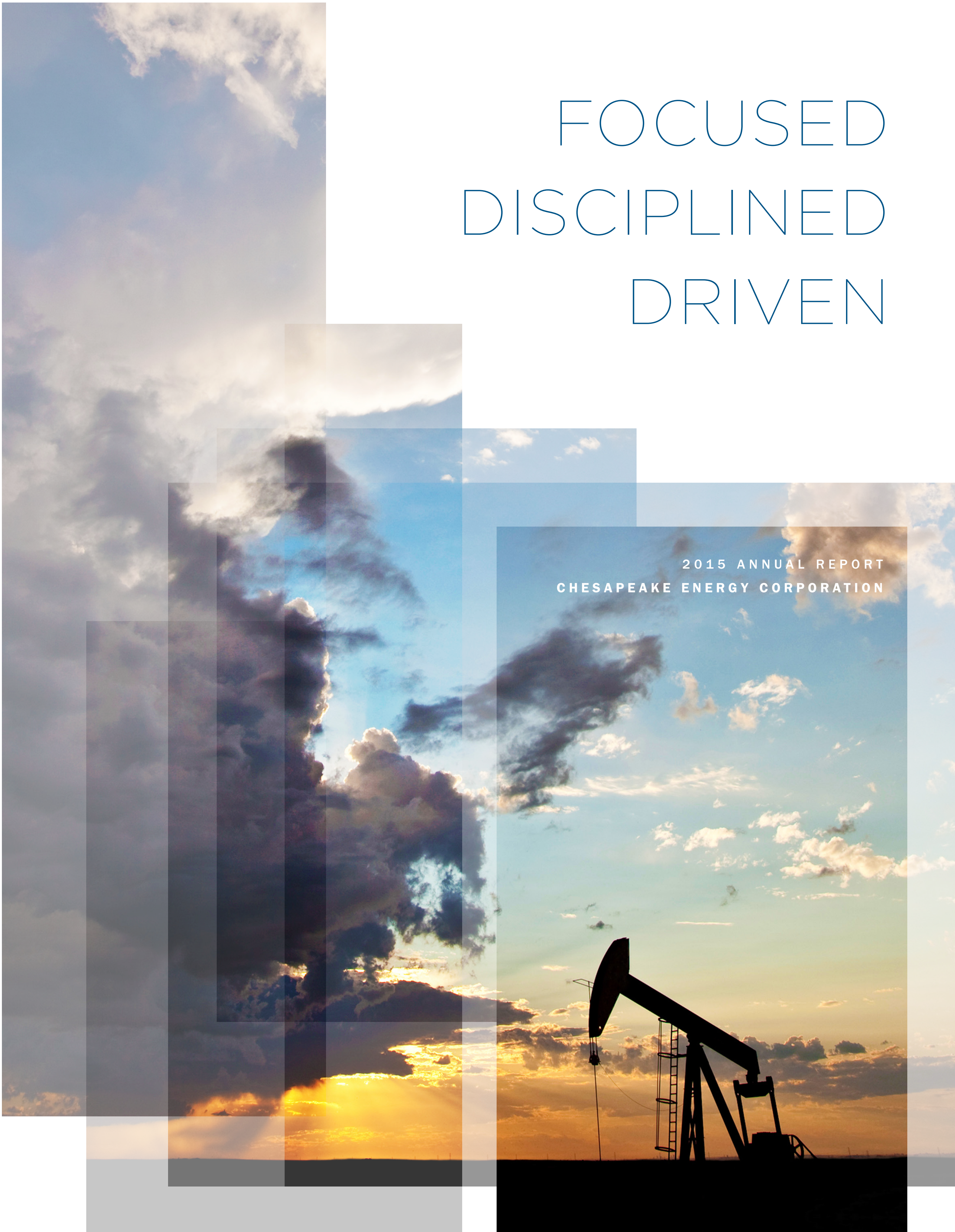

2015 ANNUAL REPORT

CHESAPEAKE ENERGY CORPORATION

Dear Fellow Shareholders:

In 2013, Chesapeake Energy began a transformation process to become a top-performing E&P company through our strategies of financial discipline and profitable and efficient growth. We have made significant progress operationally, financially and culturally — building a company based on value and competitive performance, despite the challenging commodity price environment.

While 2015 presented extremely difficult challenges for the entire energy industry, Chesapeake's portfolio of diverse, high-quality unconventional assets and talented employees provided — and continues to provide — strength, stability and optionality to successfully combat the depressed commodity price environment. We remain dedicated and focused on improving the financial and long-term strength of the company through creative and innovative efficiencies, lowering costs and reducing debt.

In 2015, our improved capital efficiency enabled us to reduce our capital program, yet still increase production year over year by 8% (adjusted for asset sales). We invested approximately $3.6 billion — a reduction of 46% in our capital expenditures compared to 2014. We also generated significant savings in our controllable cash costs. We reduced general and administrative costs by 27%, or $87 million, and reduced production costs by 13%, or $162 million. In addition, we renegotiated gathering agreements in the Haynesville and Utica shales that significantly improved our per-unit gathering rates, drilling economics and operational efficiency. We expect to secure further improvements in our midstream gathering and transportation costs in 2016. We have already successfully renegotiated certain midstream agreements in the first quarter that will enhance our annualized EBITDA by approximately $50 million through lower transportation volume commitments and lower fees on pipelines in the Haynesville, Barnett and Eagle Ford shales.

We made significant progress towards debt reduction by reducing our total principal debt balances from approximately $11.8 billion at year-end 2014 to approximately $9.5 billion as of February 2016. We privately exchanged certain existing senior unsecured notes for new 8.00% senior second lien secured notes, reducing our debt by approximately $1.5 billion. We also took advantage of the significant discounts in debt security pricing and repurchased a portion of our debt in the open market. Since September 2015, we have exchanged or repurchased approximately $600 million of debt maturing in 2017. In aggregate, we have reduced our annual interest payments by approximately $34 million. We are continuing these efforts in 2016.

While we are pleased with our progress over the last few years, the Board of Directors and management team recognize that much work remains ahead. In 2016, we are focusing on: maximizing liquidity through reducing our capital budget; optimizing our portfolio through divestitures of assets; increasing our EBITDA by continuing to improve our gathering and transportation agreements and reducing our production and G&A expenses; and continuing to reduce our debt, focusing primarily on our 2017 and 2018 maturities. To further improve our near-term liquidity, we closed or signed approximately $700 million in asset divestitures in the first quarter of 2016 and we intend to pursue additional, non-core divestitures in the range of $500 million to $1 billion by the end of the year.

On behalf of the Board of Directors and the entire management team, we would like to thank you for your trust and investment as we continue the transformation of Chesapeake Energy into a top-performing E&P company. We remain committed and focused on creating long-term shareholder value, while demonstrating leadership in safety and environmental stewardship in all aspects of our business.

R. Brad Martin

Robert D. Lawler

R. Brad Martin
Chairman of the Board

Robert D. Lawler
President, Chief Executive Officer and Director

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

FORM 10-K

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2015
[ ] 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
3.25% Senior Notes due 2016	New York Stock Exchange
6.25% Senior Notes due 2017	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
Floating Rate Senior Notes due 2019	New York Stock Exchange
6.625% Senior Notes due 2020	New York Stock Exchange
6.875% Senior Notes due 2020	New York Stock Exchange
6.125% Senior Notes due 2021	New York Stock Exchange
5.375% Senior Notes due 2021	New York Stock Exchange
4.875% Senior Notes due 2022	New York Stock Exchange
5.75% Senior Notes due 2023	New York Stock Exchange
2.75% Contingent Convertible Senior Notes due 2035	New York Stock Exchange
2.5% Contingent Convertible Senior Notes due 2037	New York Stock Exchange
2.25% Contingent Convertible Senior Notes due 2038	New York Stock Exchange
4.5% Cumulative Convertible Preferred Stock	New York Stock Exchange

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

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

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

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

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

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

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2015 was approximately $7.4 billion. As of February 9, 2016, there were 664,992,714 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2016 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
2015 ANNUAL REPORT ON FORM 10-K
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PART I

Item 1. *Business*

Unless the context otherwise requires, references to “Chesapeake”, the “Company”, “us”, “we” and “our” in this report are to Chesapeake Energy Corporation together with its subsidiaries. Our principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, and our main telephone number at that location is (405) 848-8000. Definitions of oil and gas industry terms appearing in this report can be found under *Glossary of Oil and Gas Terms* beginning on page 19.

Our Business

Chesapeake is currently the second-largest producer of natural gas and the 14th largest producer of oil and natural gas liquids (NGL) in the United States. We own interests in approximately 43,700 oil and natural gas wells and produced an average of approximately 661 mboe per day in the 2015 fourth quarter, net to our interest. We have a large and geographically diverse resource base of onshore U.S. unconventional natural gas and liquids assets. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Anadarko Basin in northwestern Oklahoma and the Texas Panhandle; and the Niobrara Shale in the Powder River Basin in Wyoming. Our natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin in Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. We also own oil and natural gas marketing and natural gas gathering and compression businesses.

The Company's estimated proved reserves as of December 31, 2015 were 1.504 bboe, a decrease of 965 mmboe, or 39%, from 2.469 bboe as of December 31, 2014. The 2015 proved reserve movement included 1.098 bboe of downward revisions resulting primarily from lower average oil and natural gas prices offset by 231 mmboe of extensions and discoveries and 213 mmboe of upward revisions resulting from changes to previous estimates as further discussed below in *Oil, Natural Gas and NGL Reserves* and in *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report. In 2015, we produced 248 mmboe and divested 63 mmboe of estimated proved reserves. Before basis differential adjustments, oil and natural gas prices used in estimating proved reserves decreased substantially as of December 31, 2015 compared to December 31, 2014 using the trailing 12-month average prices required by the Securities and Exchange Commission (SEC). Oil prices decreased by $44.70 per bbl, or 47%, to $50.28 per bbl from $94.98 per bbl. Natural gas prices decreased $1.77 per mcf, or 41%, to $2.58 per mcf from $4.35 per mcf. Proved developed reserves represented 84% of our proved reserves as of December 31, 2015 compared to 75% as of December 31, 2014.

Our daily production for 2015 averaged 679 mboe, a decrease of 27 mboe, or 4%, from the 706 mboe of daily production for 2014, and consisted of approximately 114,000 bbls of oil (17% on an oil equivalent basis), approximately 2.9 bcf of natural gas (72% on an oil equivalent basis) and approximately 76,700 bbls of NGL (11% on an oil equivalent basis). Our average daily oil production decreased by 2%, or approximately 2 mbbls per day; our average daily natural gas production decreased by 2%, or approximately 69 mmcf per day; and our average daily NGL production decreased by 15%, or approximately 14 mbbls per day over the average daily production for 2014.

Information About Us

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

Business Strategy

Chesapeake’s strategy for 2016 is to focus on maximizing liquidity, improving margins and improving the value of our significant positions in premier U.S. onshore resource plays. We continue to apply financial discipline to all aspects of our business with the goal of increasing financial and operational flexibility through lower, value-driven spending. Our 2016 capital program will be focused on efficient investments that can improve our cash flow generating ability in a depressed commodity price environment. This strategy results in utilizing fewer rigs than in 2015, however, to improve cash flow, we anticipate increasing completion crews to capitalize on prior investments and generate revenues from initial production on new wells.

As part of a broader effort to decrease our financial complexity and increase our liquidity, we took the following actions in 2015:

- reduced total capital expenditures in 2015 compared to 2014 by approximately 46% in response to the lower commodity price environment;
- amended our revolving credit facility to give us greater flexibility and access to liquidity;
- exchanged certain senior notes for new secured second lien notes to reduce and extend our future debt and interest obligations;
- eliminated quarterly dividends on our common stock;
- 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 prices;
- removed drilling and overriding royalty interest commitments related to our CHK Cleveland Tonkawa (CHK C-T) subsidiary; and
- restructured certain gathering agreements to improve our per-unit gathering rates beginning in 2016, satisfy minimum volume commitment obligations and increase realized pricing per mcf of natural gas.

In 2016, we intend to build on these actions to better position Chesapeake to create additional value as we work to improve liquidity and increase the value of our asset base. We expect our recent decision to suspend payment of dividends on our convertible preferred stock and the sales of assets that do not fit in our strategic priorities to provide increased liquidity. In addition, we are strengthening our balance sheet and improving our liquidity position by repurchasing, at a discount, certain of our debt instruments that are scheduled to mature or are subject to a demand repurchase in 2016 and 2017.

Our substantial inventory of hydrocarbon resources, including our undeveloped acreage, provides a strong foundation to create future value. We have seen and continue to see increased efficiencies and operational improvements, including increased well productivity from larger completions and lower production declines due to a greater focus on strengthening our base production. Building on our strong and diverse asset base, we believe that our dedication to financial discipline, the flexibility of our capital program, and our continued focus on safety and environmental stewardship will provide many opportunities to create greater future value for Chesapeake and its stakeholders in 2016 and beyond.

Operating Divisions

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

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

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

Well Data

As of December 31, 2015, we held an interest in approximately 43,700 gross (18,000 net) productive wells, including 32,200 properties in which we held a working interest and 11,500 properties in which we held an overriding or royalty interest. Of the wells in which we had a working interest, 27,000 gross (15,600 net) were classified as natural gas productive wells and 5,200 gross (2,400 net) were classified as oil productive wells. Chesapeake operated approximately 20,800 of its 32,200 productive wells in which we had a working interest. During 2015, we drilled or participated in 611 gross (409 net) wells as operator and participated in another 203 gross (19 net) wells completed by other operators. We operate approximately 92% 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.

	2015				2014				2013			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	806	99	423	100	1,784	99	629	99	1,704	99	847	99
Dry	1	1	—	—	3	1	1	1	21	1	9	1
Total	807	100	423	100	1,787	100	630	100	1,725	100	856	100
Exploratory:												
Productive	7	100	5	100	145	95	46	88	209	97	124	96
Dry	—	—	—	—	8	5	6	12	6	3	5	4
Total	7	100	5	100	153	100	52	100	215	100	129	100

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

	2015		2014		2013	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Southern	537	258	1,448	473	1,352	698
Northern	277	170	492	209	588	287
Total	814	428	1,940	682	1,940	985

At December 31, 2015, we had 300 gross (180 net) wells in drilling or completing status.

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

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

	Years Ended December 31,		
	2015	2014	2013
Net Production:			
Oil (mmbbl)	42	42	41
Natural gas (bcf)	1,070	1,095	1,095
NGL (mmbbl)	28	33	21
Oil equivalent (mmboe)[a]	248	258	244
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 45.77	$ 89.41	$ 96.78
Natural gas ($ per mcf)	$ 2.31	$ 4.14	$ 3.44
NGL ($ per bbl)	$ 14.06	$ 30.95	$ 36.08
Oil equivalent ($ per boe)	$ 19.23	$ 36.21	$ 34.77
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 66.91	$ 85.04	$ 94.14
Natural gas ($ per mcf)	$ 2.72	$ 3.97	$ 3.45
NGL ($ per bbl)	$ 14.06	$ 30.95	$ 36.08
Oil equivalent ($ per boe)	$ 24.54	$ 34.74	$ 34.36
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 4.22	$ 4.69	$ 4.74
Oil, natural gas and NGL gathering, processing and transportation	$ 8.55	$ 8.43	$ 6.44

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

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2015 with respect to our estimated proved reserves, the associated estimated future net revenue and present value (discounted at an annual rate of 10%) of estimated future net revenue before and after future income taxes (standardized measure). Neither the pre-tax present value of estimated future net revenue nor the after-tax standardized measure is intended to represent the current market value of the estimated oil, natural gas and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2015			
	Oil	Natural Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
Proved developed	216	5,329	158	1,262
Proved undeveloped	98	712	25	242
Total proved[(a)]	314	6,041	183	1,504

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[(b)]	$ 7,153	$ 2,334	$ 9,487
Present value of estimated future net revenue[(b)]	$ 3,948	$ 779	$ 4,727
Standardized measure[(b)(c)]			$ 4,693

Operating Division	Oil	Natural Gas	NGL	Oil Equivalent	Percent of Proved Reserves	Present Value
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)		($ millions)
Southern	272	3,252	110	924	61%	$ 3,347
Northern	42	2,789	73	580	39%	1,380
Total	314	6,041	183	1,504	100%	$ 4,727 [(b)]

(a) Includes 1 mmbbl of oil, 32 bcf of natural gas and 3 mmbbl of NGL reserves owned by the Chesapeake Granite Wash Trust, 1 mmbbl of oil, 16 bcf of natural gas and 2 mmbbl of NGL of which are attributable to the noncontrolling interest holders.

(b) Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of December 31, 2015. 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, 2015. The prices used in our reserve reports were $50.28 per bbl of oil and $2.58 per mcf of natural gas, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2015. The amounts shown do not give effect to nonproperty-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue differs from the standardized measure only because the former does not include the effects of estimated future income tax expenses ($34 million as of December 31, 2015).

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

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

As of December 31, 2015, our proved reserve estimates included 242 mmboe of reserves classified as proved undeveloped, compared to 605 mmboe as of December 31, 2014. Presented below is a summary of changes in our proved undeveloped reserves (PUDs) for 2015.

	Total
	(mmboe)
Proved undeveloped reserves, beginning of period	605
Extensions, discoveries and other additions	82
Revisions of previous estimates	(376)
Developed	(67)
Sale of reserves-in-place	(2)
Purchase of reserves-in-place	—
Proved undeveloped reserves, end of period	242

As of December 31, 2015, there were no PUDs that had remained undeveloped for five years or more. In 2015, we invested approximately $720 million, net of drilling and completion cost carries of $18 million, to convert 67 mmboe of PUDs to proved developed reserves. In 2016, we estimate that we will invest approximately $347 million for PUD conversion. The downward revisions of 376 mmboe of PUDs in 2015 were related to a 505 mmboe reduction due to lower commodity prices partially offset by positive revisions of 129 mmboe resulting mainly from improved efficiencies and performance in our Eagle Ford assets.

The future net revenue attributable to our estimated PUDs of $2.3 billion as of December 31, 2015, and the $779 million present value thereof, have been calculated assuming that we will expend approximately $1.4 billion to develop these reserves ($347 million in 2016, $318 million in 2017, $437 million in 2018, $153 million in 2019 and $119 million in 2020), although the amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs, commodity prices and the availability of capital. Chesapeake's developmental drilling schedules are subject to revision and reprioritization throughout the year resulting from unknowable factors such as unexpected developmental drilling results, title issues and infrastructure availability or constraints.

Our proved undeveloped extensions, discoveries and other additions included 82 mmboe of reserves that were booked due to the application of reliable technology, including statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, reservoir simulation and volumetric analysis. The statistical nature of production performance coupled with highly certain reservoir continuity or quality and sufficient proved undeveloped locations established the reasonable certainty criteria required for booking proved reserves.

Our annual net decline rate on current proved producing properties is projected to be 31% in 2016, 21% in 2017, 17% in 2018, 14% in 2019 and 12% in 2020. Of our 1,262 mmboe of proved developed reserves as of December 31, 2015, approximately 97 mmboe, or 8%, were non-producing.

Chesapeake's ownership interest used for calculating proved reserves and the associated estimated future net revenue assumes maximum participation by other parties to our farm-out and participation agreements. SEC pricing used for calculating the estimated future net revenue attributable to our proved reserves does not reflect actual market prices for oil and natural gas production sold subsequent to December 31, 2015.

The Company's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2015, 2014 and 2013, along with the changes in quantities and standardized measure of the reserves for each of the three years then ended, are shown in *Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities* included in Item 8 of Part II of this report. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

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

Reserves Estimation

Chesapeake's Corporate Reserves Department prepared approximately 41% of the proved reserves estimates (by volume), and approximately 23% of the proved reserves estimates (by value), disclosed in this report. Those estimates were based upon the best available production, engineering and geologic data.

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

- 25 years of practical experience working for major oil companies, including 17 years in reservoir engineering responsible for estimation and evaluation of reserves;
- Bachelor of Science degree in Petroleum Engineering;
- registered professional engineer in the state of Texas; and
- member in good standing of the Society of Petroleum Engineers.

We ensure that the key members of our Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserves estimates. Each of our Corporate Reserves Advisors has more than 25 years' experience in reserve estimation as a reservoir engineer. Our engineering technicians have a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field. We maintain a continuous education program for our engineers and technicians on new technologies and industry advancements as well as refresher training on basic skills and analytical techniques.

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

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

We engaged two third-party engineering firms to prepare approximately 59% by volume and 77% by value of our estimated proved reserves at year-end 2015. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2015 is presented below.

	% Prepared (by Volume)	% Prepared (by Value)	Operating Division
Ryder Scott Company, L.P.	36%	58%	Southern
PetroTechnical Services, Division of Schlumberger Technology Corporation	23%	19%	Northern

Copies of the reports issued by the engineering firms are filed with this report as Exhibits 99.1 and 99.2. The qualifications of the technical person at each of these firms primarily responsible for overseeing his firm's preparation of the Company's reserve estimates are set forth below.

Ryder Scott Company, L.P.

- over 30 years of practical experience in the estimation and evaluation of reserves
- registered professional engineer in the state of Texas
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers
- Bachelor of Science degree in Electrical Engineering

PetroTechnical Services, Division of Schlumberger Technology Corporation

- 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
- 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 acquisitions, exploration and development activities during the periods indicated:

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
Acquisition of Properties:			
Proved properties	$ —	$ 214	$ 22
Unproved properties	454	1,224	997
Exploratory costs	112	421	699
Development costs	2,941	4,204	4,888
Costs incurred(a)(b)	$ 3,507	$ 6,063	$ 6,606

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $51 million, $679 million and $884 million in 2015, 2014 and 2013, respectively.

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

Capitalized interest	$ 410	$ 604	$ 815
Asset retirement obligations	$ (15)	$ 39	$ 7

A summary of our exploration and development, acquisition and divestiture activities in 2015 by operating division is as follows:

	Gross Wells Drilled	Net Wells Drilled	Exploration and Development	Acquisition of Unproved Properties	Acquisition of Proved Properties	Sales of Unproved Properties	Sales of Proved Properties	Total[(a)]
			($ in millions)					
Southern	537	258	$ 1,833	$ 120	$ —	$ (128)	$ (1,026)	$ 799
Northern	277	170	1,220	334	—	(91)	(3)	1,460
Total	814	428	$ 3,053	$ 454	$ —	$ (219)	$ (1,029)	$ 2,259

(a) Includes capitalized internal costs of $196 million and related capitalized interest of $410 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, 2015. "Gross" acres are the total number of acres in which we own a working interest. "Net" acres refer to gross acres multiplied by our fractional working interest. Acreage numbers do not include our unexercised options to acquire additional acreage.

	Developed Leasehold		Undeveloped Leasehold		Fee Minerals		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
	(in thousands)							
Southern	5,420	2,704	1,205	579	164	30	6,789	3,313
Northern	1,885	1,424	4,932	2,996	701	438	7,518	4,858
Total	7,305	4,128	6,137	3,575	865	468	14,307	8,171

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 as of December 31, 2015 the expiration periods of gross and net undeveloped leasehold acres.

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2016	1,691	1,067
2017	1,084	663
2018	425	169
After 2018	2,937	1,676
Total[(a)]	6,137	3,575

(a) Includes 1.565 million gross (797,272 net) held-by-production acres that will remain in force as our production continues on the subject leases, and other leasehold acreage where management anticipates the lease to remain in effect past the primary term of the agreement due to our contractual option to extend the lease term.

Marketing, Gathering and Compression

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

Marketing

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

Oil production is generally sold under market-sensitive short-term or spot price contracts. Natural gas and NGL production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, we receive a percentage of the resale price received from the ultimate purchaser. Under percentage-of-index contracts, the price we receive is tied to published indices. Sales to BP PLC constituted approximately 14% of our total revenues (before the effects of hedging) for the year ended December 31, 2015. Sales to Exxon Mobil Corporation constituted approximately 12% of our total revenues (before the effects of hedging) for the year ended December 31, 2014. There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the year ended December 31, 2013.

Midstream Gathering Operations

Historically, we invested, directly and through affiliates, in gathering systems and processing facilities to complement our natural gas operations in regions where we had significant production and additional infrastructure was required. These systems were designed primarily to gather our production for delivery into major intrastate or interstate pipelines. In addition, our midstream business provides services to joint working interest owners and other third-party customers. We generate revenues from our gathering, treating and compression activities through various gathering rate structures. We also process a portion of our natural gas at various third-party plants.

In 2012 and 2013, we sold substantially all of our midstream business, including most of our gathering assets. We continue to own certain gathering pipelines primarily associated with vertical well production in the eastern United States and four natural gas processing facilities located in West Virginia. See Note 16 of the notes to the consolidated financial statements included in Item 8 of Part II of this report for further discussion of the midstream sales transactions.

Compression Operations

Since 2003, we have operated our compression business through our wholly owned subsidiaries Compass Manufacturing, L.L.C. (Compass) and MidCon Compression, L.L.C. (MidCon). Compass designs, engineers, fabricates, installs and sells natural gas compression units, accessories and equipment used in the production, treatment and processing of oil and natural gas. A majority of the completed compressors are sold to MidCon. MidCon operates wellhead and system compressors, with approximately 450,000 horsepower of compression, to facilitate the transportation of natural gas primarily produced from Chesapeake-operated wells.

Spin-Off of Oilfield Services Business

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

Following the spin-off, we have no ownership interest in SSE. Therefore, we ceased to consolidate SSE's assets and liabilities as of the spin-off date. Because we expect to have significant continued involvement associated with SSE's future operations through the various agreements described in Note 13 of the notes to our consolidated financial statements included in Item 8 of Part II of this report, our former oilfield services segment's historical financial results for periods prior to the spin-off continue to be included in our historical financial results as a component of continuing operations.

Competition

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

Regulation – General

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

Exploration and Production Operations

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

- seismic operations;
- the location of wells;
- construction and operations activities, including in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- the method of drilling and completing wells;
- production operations, including the installation of flowlines and gathering systems;
- air emissions and hydraulic fracturing;

- the surface use and restoration of properties upon which oil and natural gas facilities are located, including the construction of well pads, pipelines, impoundments and associated access roads;
- water withdrawal;
- the plugging and abandoning of wells;
- the generation, storage, transportation treatment, recycling or disposal of hazardous waste, fluids or other substances in connection with operations;
- the construction and operation of underground injection wells to dispose of produced water and other liquid oilfield wastes;
- the construction and operation of surface pits to contain drilling muds and other fluids associated with drilling operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

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

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

Hydraulic Fracturing

Hydraulic fracturing is typically regulated by state oil and gas regulatory authorities, including specifically the requirement to disclose certain information related to hydraulic fracturing operations. We follow applicable legal requirements for groundwater protection in our operations that are subject to supervision by state and federal regulators (including the BLM on federal acreage). Furthermore, our well construction practices require the installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers. Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. In June 2015, New York created a statewide ban on hydraulic fracturing. Similar bans have been adopted by local governments, although many of these actions are the subject of legal challenges.

In February 2014, the EPA released its final guidance on the use of diesel additives in hydraulic fracturing operations. The EPA is also engaged in a study of the potential impacts of hydraulic fracturing activities on drinking water resources in these states where the EPA is the permitted authority, including Pennsylvania, with a progress report released in late 2012 and a draft report released in June 2015. It concluded that hydraulic fracturing activities have not led to widespread systematic impacts on drinking water resources in the U.S., but there are above and below-ground mechanisms by which hydraulic fracturing could affect drinking water resources. In addition, in March 2015, the BLM issued a final rule to regulate hydraulic fracturing on federal and Indian land; however, enforcement of the rule has been delayed pending a decision in a legal challenge in the U.S. District Court of Wyoming. Further, the EPA issued an Advanced Notice of Proposed Rulemaking in May 2014 seeking comments relating to the information that should be reported or disclosed for hydraulic fracturing chemical substances and mixtures and mechanisms for obtaining this information. These actions, in conjunction with other analyses by federal and state agencies to assess the impacts of hydraulic fracturing could spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities. For example, on February 16, 2016, the Oklahoma Corporation Commission (OCC) implemented a volume reduction plan for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation. The OCC's plan, in conjunction with a 191,000 barrel per day reduction plan already implemented in the Byron/Cherokee area, will create a total volume cutback of over 500,000 barrels per day, or about 40%.

Restrictions on hydraulic fracturing could make it prohibitive to conduct our operations, and also reduce the amount of oil, natural gas and NGL that we are ultimately able to produce in commercial quantities from our properties. For further discussion, see Item *1A. Risk Factors – Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.*

Midstream Operations

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

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

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

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

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

Regulation – Environment, Health and Safety

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

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

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

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

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

Hazardous Substances and Waste

Federal and state laws, in particular the federal Resource Conservation and Recovery Act (RCRA) regulate hazardous and non-hazardous wastes. In the course of our operations, we generate petroleum hydrocarbon wastes, such as drill cuttings, produced water and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, although they are regulated under other federal and state waste laws. At various times in the past, proposals have been made to amend RCRA to 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 of and would cause us, as well as our competitors, to incur 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 of or released into the environment. This can include removing or remediating wastes or hazardous substances disposed of 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 of or arranged for the disposal of hazardous substances at the site, and any person who accepted hazardous substances for transportation to the site. CERCLA and analogous state laws also authorize the EPA, state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and/or seek recovery of the costs of such actions from responsible classes of persons.

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

Air Emissions

Our operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. Among other things, these laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, 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.

In 2012, the EPA published final New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amended the existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and gas production, transmission and distribution facilities with a compliance deadline of January 1, 2015. In 2013 and 2014, the EPA issued updated rules regarding storage tanks and made additional clarifications to these rules. In December 2014, the EPA issued additional amendments to these rules that, among other things, distinguish between multiple flowback stages during completion of hydraulically fractured wells and clarify that storage tanks permanently removed from service are not affected by any requirements. In July 2015, the EPA finalized two updates to the rules addressing the definition of low pressure gas wells and references to tanks that are connected to one another (referred to as connected in parallel). Further, in September 2015, the EPA issued a proposed rule that would update and expand the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In January 2016, the BLM also proposed rules to require additional efforts by producers to reduce venting, flaring, and leaking of natural gas produced on federal and Indian lands.

In 2010, the EPA published rules that require monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems. We, along with other industry groups, filed suit challenging certain provisions of the rules and are engaged in settlement negotiations to amend and correct the rules. We anticipate final resolution to this litigation in the near future. In October 2015, EPA finalized new reporting requirements for boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. In January 2016, the EPA proposed two more revisions to the greenhouse gas reporting rule. One proposal addresses leaks from oil and gas equipment and the other proposal is intended to improve implementation of the rule, while also proposing confidentiality determinations for the reporting of certain data elements to the program.

In addition, in October 2015, the EPA published its final rule revising downward the ozone national ambient air quality standard to 70 parts per billion. Our business and operations could be subject to increased operating and compliance costs associated with these regulations.

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 U.S. waters. In June 2015, the EPA and USACE jointly published a rule regarding the definition of waters of the United States that substantially expands the waters regulated under the CWA. Implementation of the rule was temporarily stayed in October 2015 by the U.S. Court of Appeals for the Sixth Circuit, pending further action. The placement of dredge or fill material into jurisdictional water or U.S. wetlands is prohibited, except in accordance with the terms of a permit issued by the USACE. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state agency delegated with EPA's authority. In April 2015, the EPA also published proposed pretreatment standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works (POTWs). Further, Chesapeake's corporate policy prohibits discharge of produced water to surface waters. Spill prevention, control and countermeasure regulations require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities and construction activities.

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

Health and Safety

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

Endangered Species

The Endangered Species Act (ESA) restricts activities that may affect areas that contain 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, as a result of a settlement reached in 2011, the U.S. Fish and Wildlife Service is required to make a determination on the listing of more than 250 species as endangered or threatened over the next several years. The designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity or the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

Global Warming and Climate Change

At the federal level, EPA regulations require us to establish and report an inventory of greenhouse gas emissions. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change, such as the President’s Climate Action Plan which calls for reducing methane emissions, could require us to incur additional operating costs and could adversely affect demand for the oil and natural gas that we sell. As discussed above, the EPA proposed new standards of performance limiting methane emissions from oil and gas sources in 2015. The potential increase in our operating costs could include new or increased costs to (i) obtain permits, (ii) operate and maintain our equipment and facilities (through the reduction or elimination of venting and flaring of methane), (iii) install new emission controls on our equipment and facilities, (iv) acquire allowances authorizing our greenhouse gas emissions, (v) pay taxes related to our greenhouse gas emissions and (vi) administer and manage a greenhouse gas emissions program. In addition to these federal actions, various state governments and/or regional agencies may consider enacting new legislation and/or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations.

Title to Properties

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

Operating Hazards and Insurance

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

Chesapeake maintains a control of well policy with a $50 million single well limit and a $100 million multiple wells limit that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. Chesapeake also carries a $460 million comprehensive general liability umbrella policy and a $150 million pollution liability policy. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks, and policy limits scale to Chesapeake’s working interest percentage in certain situations. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. Our insurance coverage may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

Facilities

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

Executive Officers

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

Robert D. (“Doug”) Lawler, 49, 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., 39, has served as Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso served as Vice President – Finance of the Company and Chief Financial Officer of Chesapeake's wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., from August 2008 to November 2010.

M. Christopher Doyle, ***Executive Vice President – Operations, Northern Division***

M. Christopher Doyle, 43, has served as Executive Vice President – Operations, Northern Division since January 2015 and previously served as Senior Vice President – Operations, Northern Division since August 2013. Prior to joining Chesapeake, Mr. Doyle served for 18 years at Anadarko in various positions of increasing responsibility within operations, finance and planning including international assignments in Algeria and London. His positions at Anadarko included Vice President of Operations from May to August 2013; Director, Corporate Planning from July 2012 to May 2013; General Manager – Appalachian Basin from June 2009 to July 2012; and Manager, Reserves and Planning – Southern Region from January to June 2009.

Frank Patterson, ***Executive Vice President – Exploration, Technology & Land***

Frank Patterson, 57, has served as Executive Vice President – Exploration, Technology & Land since May 2015. Before joining Chesapeake, Mr. Patterson served in various roles at Anadarko from 2006 to 2015, most recently as Senior Vice President – International Exploration. Prior to that he was Vice President – Deepwater Exploration at Kerr-McGee and Manager – Geology at Sun E&P/Oryx Energy.

Mikell J. Pigott, ***Executive Vice President – Operations, Southern Division***

Mikell J. ("Jason") Pigott, 42, has served as Executive Vice President – Operations, Southern Division since January 2015 and previously served as 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, 48, has served as Executive Vice President – General Counsel and Corporate Secretary since January 2014. Previously, he served as Senior Vice President – Legal and General Counsel since October 2012 and as Corporate Secretary since August 2013. Mr. Webb first joined Chesapeake in May 2012 on a contract basis as Chief Legal Counsel. Prior to joining Chesapeake, Mr. Webb was an attorney with the law firm of McAfee & Taft from 1995 to October 2012.

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

Michael A. Johnson, 50, has served as Senior Vice President – Accounting, Controller and Chief Accounting Officer since 2000. He served as Vice President of Accounting and Financial Reporting from 1998 to 2000 and as Assistant Controller from 1993 to 1998.

Other Senior Officer

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

Cathlyn L. Tompkins, 55, has served as Senior Vice President – Information Technology and Chief Information Officer since 2006. Ms. Tompkins served as Vice President – Information Technology from 2005 to 2006.

Employees

Chesapeake had approximately 4,400 employees as of December 31, 2015.

Glossary of Oil and Gas Terms

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

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

Bboe. One billion barrels of oil equivalent.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

Bbtu. One billion British thermal units.

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

Boe. Barrel of oil equivalent.

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

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

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

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

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

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

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

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

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

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

Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the NYMEX.

Horizontal Drilling. Drilling at angles greater than 70 degrees from vertical.

Mboe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

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

Mmboe. One million barrels of oil equivalent.

Mmbtu. One million btus.

Mmcf. One million cubic feet.

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

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

NYMEX. New York Mercantile Exchange.

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

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

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

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

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

Proved Properties. Properties with proved reserves.

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

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

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

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

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

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

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

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

Tbtu. One trillion British thermal units.

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

Unproved Properties. Properties with no proved reserves.

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

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

West Texas Intermediate (WTI). A grade of crude oil used as a benchmark in oil pricing.

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 continued low prices or lower prices for an extended period of time are likely to have a material adverse effect on our business.

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

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

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

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. Oil and natural gas prices continued to decline and remain low throughout 2015 and into the 2016 first quarter. As of February 23, 2016, 56% and 58% of our forecasted 2016 oil production and natural gas production, respectively, was hedged under swaps. Even with oil and natural gas derivatives currently in place to mitigate price risks associated with a portion of our future production, our 2016 revenue and results of operations are expected to be below 2015 levels and will be further adversely affected if commodity prices remain at current levels. In addition, a prolonged extension of prices at these levels will reduce the quantities of reserves that may be economically produced.

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

As of December 31, 2015, we had approximately $9.7 billion in principal amount of debt (including current maturities), and borrowing capacity of approximately $4.0 billion under our revolving credit facility, which was undrawn (other than letters of credit issued thereunder in the aggregate amount of $16 million) as of December 31, 2015. Approximately $1.9 billion principal amount of debt matures or can be put to us in 2017 and approximately $878 million principal amount of debt matures or can be put to us in 2018. We also had a net working capital deficit of approximately $1.205 billion as of December 31, 2015.

The level of and terms and conditions governing our debt:

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

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

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

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

Disruptions in the capital and credit markets, in particular with respect to companies in the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Recent decreases in commodity prices, among other factors, are causing and may continue to cause lenders to increase interest rates, enact tighter lending standards which we may not satisfy as a result of our debt level or otherwise, refuse to refinance existing debt around maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. In addition, the filing of this annual report will render us unable to use our currently effective universal shelf Form S-3 registration statement. Because we failed to pay dividends on our convertible preferred stock during the 2016 first quarter, we will no longer meet the criteria of a "well-known seasoned issuer" on the date of filing of this report, which previously enabled us to, among other things, file automatically effective shelf registration statements. Accordingly, even if we were able to access the capital markets, any attempt to do so could be more expensive or subject to significant delays. If we are unable to access the capital and credit markets on favorable terms or at all, it could materially adversely affect our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

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

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any cash flow insufficiency would materially adversely impact our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt. 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. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy, the impact of legislative or regulatory actions on how we conduct our business or competitive initiatives of our competitors, are beyond our control. 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.

Our liquidity is dependent on many factors, including availability under our credit facility and cost and access to capital and credit markets, which are affected by the price and performance of our equity and debt securities. If the borrowing base under our credit facility is reduced and we are otherwise unable to maintain an adequate liquidity position, we may not have the financial flexibility to meet our debt obligations or manage our business, including activities that we do not currently fund with our credit facility but may in the future, such as our planned capital expenditures.

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

We cannot assure you that our business will generate sufficient cash flow from operations to service our outstanding indebtedness, or that future borrowings will be available to us in an amount sufficient to enable us to pay or refinance our indebtedness, manage our working capital or fund our other capital needs. We do not expect to generate sufficient cash flow from operations to satisfy our 2017 and 2018 debt maturities. Accordingly, we are undertaking and will continue to undertake various alternative financing plans, which may include:

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

However, we cannot assure you that we would be able to implement alternative financing plans, if necessary, on commercially reasonable terms or at all, or that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations and capital requirements or that these actions would be permitted under the terms of our various debt instruments. If commodity prices remain at depressed levels and we are unsuccessful in implementing our alternative financing plans or otherwise improving our liquidity, we may not be able to fund budgeted capital expenditures or meet our debt service requirements in 2017 and beyond.

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

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

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

Restrictive covenants in our credit facility 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.

Our credit facility imposes 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; and
- enter into transactions with affiliates.

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

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

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

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

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

Since December 2015, Moody's Investor Services, Inc. has lowered the Company's senior unsecured credit rating from "Ba3" to "Caa3", and Standard & Poor's Rating Services has lowered the Company's senior unsecured credit rating from "BB-" to "CC". The downgrades were primarily a result of the effect of low oil and natural gas prices on our ability to generate cash flow from operations. We cannot provide assurance that our credit ratings will not be further reduced if commodity prices continue to remain low. Any further downgrade to our credit ratings could negatively impact our availability and cost of capital.

Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as transportation, gathering, processing and hedging agreements. As of February 24, 2016, we have received requests to post approximately $220 million in collateral, of which we have posted approximately $92 million. We have posted the required collateral, primarily in the form of letters of credit and cash, or are otherwise complying with these contractual requests for collateral. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $698 million (excluding the supersedeas bond with respect to the 2019 Notes litigation discussed in Note 3 of the notes to our consolidated financial statements included in Item 8 of this report), which may be in the form of additional letters of credit, cash or other acceptable collateral. Any posting of collateral consisting of cash or letters of credit, which would reduce availability under our credit facility, will negatively impact our liquidity.

We expect to have further significant write downs of the carrying value of our oil and natural gas properties if commodity prices remain low.

Under the full cost method of accounting for costs related to our oil and natural gas properties, we are required to write down the carrying value of our oil and natural gas assets if capitalized costs exceed the quarterly ceiling limit, which is based on the average of commodity prices on the first day of the month over the trailing 12-month period. Such write-downs can be material. For example, for the year ended December 31, 2015, we reported non-cash impairment charges on our oil and natural gas properties totaling $18.238 billion, primarily resulting from a substantial decrease in the trailing 12-month average first-day-of-the-month oil and natural gas prices throughout 2015, and the impairment of certain undeveloped leasehold interests. The trailing 12-month average first-day-of-the-month prices used to calculate our oil and natural gas reserves decreased from $94.98 per bbl of oil and $4.35 per mcf of natural gas as of December 31, 2014 to $50.28 per bbl of oil and $2.58 per mcf of natural gas as of December 31, 2015. Oil and natural gas prices have continued to decline further in the 2016 first quarter. The NYMEX WTI index price of oil on February 22, 2016 was $31.48 per bbl, and the Henry Hub index price of natural gas was $1.82 per mcf. As of December 31, 2015, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $4.7 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of that date. Based on first-day-of-the-month index prices for January and February of 2016, as well as recent strip prices for March 2016, we reasonably expect a decrease of approximately $4.50 per barrel of oil and $0.15 per mcf of natural gas in the prices we will be using to calculate the estimated future net revenue of our proved reserves as of March 31, 2016, and such decreases are expected to reduce the present value of estimated future net revenue of our proved reserves by approximately $1.2 billion in the 2016 first quarter. Such decrease is likely to be a significant factor in the amount of impairment recorded in the 2016 first quarter. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

Significant capital expenditures are required to replace our reserves and conduct our business, and our access to capital is constrained and subject to uncertainty.

Our exploration, development and acquisition activities require substantial capital expenditures. We intend to fund our capital expenditures through cash flows from operations, cash on hand and borrowings under our revolving credit facility. Our ability to generate operating cash flow is subject to many of the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Future cash flows from operations are 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, 2015 reflect an expected decline in the production rate on our producing properties of approximately 31% in 2016 and 21% in 2017. 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, 2015, approximately 16% 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 $1.4 billion during the five years ending in 2020. You should be aware that the estimated development costs may not equal our actual costs, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove them from our reported proved reserves. In addition, under the SEC's reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included in this report represent the current market value of our estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average oil and natural gas price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2015 present value is based on $50.28 per bbl of oil and $2.58 per mcf of natural gas before basis differential adjustments. These prices are substantially higher than current 2016 prices for oil and natural gas. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

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

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

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

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

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

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

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

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

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

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

Most of our oil and natural gas derivative contracts are with eleven counterparties under bi-lateral hedging arrangements. As of December 31, 2015, we had hedged under bi-lateral arrangements 164.0 mmboe of our future production with price derivatives and 9.5 mmboe with basis derivatives. Under some of those arrangements, the counterparties' and our obligations under the bi-lateral hedging arrangements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. Under certain circumstances, the cash collateral value posted could fall below the coverage designated, and we would be required to post additional cash or letter of credit collateral under our hedging arrangements. We are in the process of changing the collateral provided for several of the counterparties, to provide that they will be secured by hydrocarbon interests. Future collateral requirements are dependent to a great extent on oil and natural gas prices.

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

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

In addition, there are ongoing governmental regulatory investigations and inquiries into such matters as our royalty practices 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 2016 and in future years. If incurred, these charges could materially adversely impact our future results of operations and liquidity.

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

Oil and natural gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, oil spills, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our prospects. 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.

For our non-operated properties, we are dependent on the operator for operational and regulatory compliance.

Our midstream and compression operations are subject to all of the risks and operational hazards inherent in transporting oil and natural gas and natural gas compression, including:

- damages to pipelines, facilities and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;
- maintenance, repairs, mechanical or structural failures;
- damages to, loss of availability of and delays in gaining access to interconnecting third-party pipeline;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack; and
- leaks of oil or natural gas as a result of the malfunction of equipment or facilities.

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

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

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

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

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

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

Several states are considering adopting regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. 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. There are also certain governmental reviews either underway or being proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. These studies assess, among other things, the risks of groundwater contamination and earthquakes caused by hydraulic fracturing and other exploration and production activities. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate or even ban such activities. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. For example, on February 16, 2016, the Oklahoma Corporation Commission (OCC) implemented a volume reduction plan for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation. The OCC's plan, in conjunction with a 191,000 barrel per day reduction plan already implemented in the Byron/Cherokee area, will create a total volume cutback of over 500,000 barrels per day, or about 40%.

We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

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

Development activities require the use of water. For example, the hydraulic fracturing process that we employ to produce commercial quantities of oil and natural gas from many reservoirs requires the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations, such as the EPA's April 2015 proposed pretreatment standards for wastewater, could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of oil and natural gas.

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

Various state governments and regional organizations 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 an inventory of greenhouse gas emissions. There were attempts at comprehensive federal legislation establishing a cap and trade program, but this legislation did not pass. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA. However, in June 2014, the U.S. Supreme Court, in UARG v. EPA, limited the application of the GHG permitting requirements under the Prevention of Significant Deterioration and Title V permitting programs to sources that would otherwise need permits based on the emission of conventional pollutants. In April 2015, the D.C. Circuit Court of Appeals narrowed the rule in accordance with the Supreme Court's decision. 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 U.S. 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 be open for signing on April 22, 2016 and will require countries to review and "represent a progression" in their intended nationally determined contributions, which set emissions reduction goals, every five years, beginning in 2020. If adopted, the Paris Agreement could further drive regulation in the United States. Restrictions on emissions of methane or carbon dioxide that have been or may be imposed in various states, or at the federal level could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil and natural gas. Finally, we note that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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

From time to time, legislative proposals are made that would, if enacted into law, make significant changes to United States tax laws, including the elimination or postponement of certain key United States federal income tax incentives currently available to independent producers of oil and natural gas. Proposals that would significantly affect us would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. In addition, legislative changes to impose additional taxes have been proposed in Louisiana and Pennsylvania. These changes, if enacted, will make it more costly for us to explore for and develop our oil and natural gas resources.

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

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

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

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

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

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

In recent years, concerns over global economic conditions, energy costs, geopolitical issues, the availability and cost of credit, and the U.S. real estate and financial markets have contributed to economic uncertainty and reduced expectations for the global economy. 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, oil spills, and explosions of natural gas transmission lines may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

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

Other companies operate some of the properties in which we have an interest. For the year ended December 31, 2015, we did not operate approximately 8% of our daily production volumes. We have limited ability to influence or control the operation or future development of these non-operated properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

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

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

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

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

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

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

In the event of a bankruptcy of SSE, our spin-off of SSE may be challenged. In addition, SSE may not perform its obligations under the agreements entered into with us in connection with the spin-off.

In June 2014 we completed the spin-off of our oilfield services business into Seventy Seven Energy Inc. (“SSE”), an independent, publicly traded company. The substantial decline in oil and natural gas prices since the completion of the spin-off has significantly and adversely affected SSE’s business, and in January 2016 SSE publicly announced that it was exploring opportunities in its capital structure that may involve reducing debt and enhancing liquidity. If SSE were to become subject to a case under the federal Bankruptcy Code or other insolvency laws, certain aspects of the spin-off could be challenged under fraudulent conveyance and transfer laws, in addition to other potential claims. Such a claim could seek to avoid transfers of assets to us or obligations incurred by SSE in connection with the spin-off and to impose other remedies, such as a judgment for the value of assets so transferred. Defending against such claims could be costly and could distract our management from other priorities. Although no assurance can be given as to the outcome of any claim, we believe we have a number of defenses to any such claim and any such claim would be without merit. In addition, SSE may not perform its indemnity and other obligations under its agreements with us, in which case we would be entitled to a general unsecured claim for damages, which may not be paid in full in the event of SSE’s bankruptcy.

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 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 or preferred stock in the near future.

In July 2015, our Board of Directors determined to eliminate quarterly cash dividends on our common stock, and in January 2016, our Board of Directors determined to suspend dividend payments on our preferred stock. Accordingly, we do not intend to pay cash dividends on our common stock or preferred stock in the foreseeable future. We currently intend to retain any earnings for the future operation and development of our business, including exploration, development and acquisition activities. Any future dividend payments will require approval by the Board of Directors. In addition, dividends may be restricted by the terms of our debt agreements. 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.

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

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

ITEM 1B. *Unresolved Staff Comments*

Not applicable.

ITEM 2. *Properties*

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

ITEM 3. *Legal Proceedings*

Litigation and Regulatory Proceedings

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

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

Redemption of 2019 Notes. See *Chesapeake Senior Notes and Contingent Convertible Senior Notes* in Note 3 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a description of pending litigation regarding our redemption in May 2013 of our 6.775% Senior Notes due 2019 (2019 Notes).

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

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

Plaintiffs have varying royalty provisions in their respective leases and oil and gas law varies from state to state. Royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations, an issue in a putative class action filed in November 2010 in the District Court of Beaver County, Oklahoma on behalf of Oklahoma royalty owners asserting claims dating back to 2004. In July 2014, this case was remanded to the trial court for further proceedings following the reversal on appeal of certification of a statewide class. We and the named plaintiff participated in mediation concerning the claims asserted in the putative class action litigation and negotiated a settlement requiring the Company to pay $119 million cash to compensate the putative settlement class for alleged past royalty underpayments in exchange for the release of claims for the ten-year period ended December 31, 2014. Following a fairness hearing, the District Court certified the settlement class and approved the $119 million settlement on July 3, 2015. In 2015, the Company paid $114 million, which was net of opted-out claims, in settlement of the case.

Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order from the Texas Multidistrict Litigation Panel to transfer a substantial portion of these lawsuits filed since June 2014 to the 348th District Court of Tarrant County for pre-trial purposes. On February 12, 2016, Chesapeake filed a motion to change venue for several other lawsuits to Harris County, or alternatively, to Tarrant County. These lawsuits, which primarily relate to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. In addition to allegations of breach of contract, a number of these lawsuits allege fraud, conspiracy, joint venture and antitrust violations by Chesapeake. Chesapeake expects that additional lawsuits will be filed by new plaintiffs making similar allegations. The lawsuits seek direct damages in varying amounts, together with exemplary damages, attorneys' fees, costs and interest.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and permanent injunction from further violations of the UTPCPL. On February 8, 2016, the Office of Attorney General amended the complaint to, among other things, add an additional UTPCPL claim and antitrust claim alleging that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases.

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

Environmental Proceedings

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

In November 2015, CALLC and the PADEP agreed to a settlement to resolve alleged violations of the Pennsylvania Clean Streams Law as a result of pad subsidence allegedly causing material to enter a nearby stream. To resolve the matter, CALLC agreed to pay a civil penalty in the amount of $1.4 million and to complete certain remediation actions by September 30, 2016.

In December 2015, CALLC and the PADEP separately entered into a settlement agreement in connection with contamination in the vicinity of one of CALLC's well pads in Bradford County, Pennsylvania. As part of the settlement agreement, CALLC paid a penalty in December 2015 in the amount of $201,969.

On January 12, 2016, we were named as a defendant in a putative class action filed in state district court in Logan County, Oklahoma. On February 16, 2016, the putative class action was moved to the Western District of Oklahoma. The petition alleges that the defendants, all exploration and production companies, have operated produced water disposal wells in a manner that has caused earthquakes and that these earthquakes have, among other things, damaged the plaintiffs' real property. The proposed class would consist of all Oklahoma residents whose property has been so damaged. The petition seeks an unspecified amount of actual and punitive damages.

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

ITEM 4. *Mine Safety Disclosures*

Not applicable.

PART II

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

Price Range of Common Stock and Dividends

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

	Common Stock		Dividend
	High	Low	Declared
Year Ended December 31, 2015:			
Fourth Quarter	$ 9.55	$ 3.56	$ —
Third Quarter	$ 11.90	$ 6.01	$ —
Second Quarter	$ 16.98	$ 10.94	$ —
First Quarter	$ 21.49	$ 13.38	$ 0.0875
Year Ended December 31, 2014:			
Fourth Quarter	$ 24.43	$ 16.41	$ 0.0875
Third Quarter	$ 29.92	$ 22.77	$ 0.0875
Second Quarter	$ 31.49	$ 25.66	$ 0.0875
First Quarter	$ 27.54	$ 23.92	$ 0.0875

As of February 11, 2016, there were approximately 2,000 holders of record of our common stock and approximately 330,000 beneficial owners.

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

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

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

Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents information about repurchases of our common stock during the quarter ended December 31, 2015:

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, 2015 through October 31, 2015	19,711	$ 7.13	—	$ 1,000
November 1, 2015 through November 30, 2015	11,684	$ 5.45	—	$ 1,000
December 1, 2015 through December 31, 2015	9,714	$ 4.27	—	$ 1,000
Total	41,109	$ 5.98	—	

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

(b) In December 2014, the Company's Board of Directors authorized the repurchase of up to $1 billion in value of its common stock from time to time. The repurchase program does not have an expiration date. As of December 31, 2015, no repurchases had been made under the program.

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of Chesapeake as of and for the years ended December 31, 2015, 2014, 2013, 2012 and 2011. The data are derived from our audited consolidated financial statements, revised to reflect the reclassification discussed below. Beginning in the 2015 fourth quarter, we have reclassified our presentation of third party transportation costs to report the costs as a component of operating expenses in the accompanying statements of operations. Previously, these costs were reflected as a deduction to oil, natural gas and NGL sales. The net effect of this reclassification had no impact on our previously reported net income, stockholders' equity or cash flows; however, previously reported oil, natural gas and NGL sales and consequently total revenues have increased from the amounts previously reported, and total operating expenses have increased by those same amounts. For additional information regarding this reclassification see Note 1 of the notes to our consolidated financial statements included in Item 8 of this report. 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,				
	2015	2014	2013	2012	2011
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA:					
Total revenues	$ 12,764	$ 23,125	$ 19,080	$ 13,422	$ 12,574
Net income (loss) available to common stockholders[(a)]	$(14,856)	$ 1,273	$ 474	$ (940)	$ 1,570
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ (22.43)	$ 1.93	$ 0.73	$ (1.46)	$ 2.47
Diluted	$ (22.43)	$ 1.87	$ 0.73	$ (1.46)	$ 2.32
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.0875	$ 0.35	$ 0.35	$ 0.35	$ 0.3375
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 17,357	$ 40,751	$ 41,782	$ 41,611	$ 41,835
Long-term debt, net of current maturities	$ 10,354	$ 11,154	$ 12,886	$ 12,157	$ 10,626
Total equity	$ 2,397	$ 18,205	$ 18,140	$ 17,896	$ 17,961

(a) Includes $18.238 billion and $3.315 billion of ceiling test write-downs on our oil and natural gas properties for the years ended December 31, 2015 and December 2012, respectively.

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

Financial Data

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

	Years Ended December 31,		
	2015	2014	2013
Net Production:			
Oil (mmbbl)	42	42	41
Natural gas (bcf)	1,070	1,095	1,095
NGL (mmbbl)	28	33	21
Oil equivalent (mmboe)[a]	248	258	244
Oil, Natural Gas and NGL Sales ($ in millions)[b]:			
Oil sales	$ 1,904	$ 3,778	$ 3,977
Oil derivatives – realized gains (losses)[c]	880	(185)	(108)
Oil derivatives – unrealized gains (losses)[c]	(536)	859	280
Total oil sales	2,248	4,452	4,149
Natural gas sales	2,470	4,535	3,767
Natural gas derivatives – realized gains (losses)[c]	437	(191)	9
Natural gas derivatives – unrealized gains (losses)[c]	(157)	535	(52)
Total natural gas sales	2,750	4,879	3,724
NGL sales	393	1,023	753
Total NGL sales	393	1,023	753
Total oil, natural gas and NGL sales	$ 5,391	$ 10,354	$ 8,626
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 45.77	$ 89.41	$ 96.78
Natural gas ($ per mcf)	$ 2.31	$ 4.14	$ 3.44
NGL ($ per bbl)	$ 14.06	$ 30.95	$ 36.08
Oil equivalent ($ per boe)	$ 19.23	$ 36.21	$ 34.77
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 66.91	$ 85.04	$ 94.14
Natural gas ($ per mcf)	$ 2.72	$ 3.97	$ 3.45
NGL ($ per bbl)	$ 14.06	$ 30.95	$ 36.08
Oil equivalent ($ per boe)	$ 24.54	$ 34.74	$ 34.36

	Years Ended December 31,		
	2015	2014	2013
Other Operating Income[(d)] ($ in millions):			
Marketing, gathering and compression net margin[(e)]	$ 243	$ (11)	$ 98
Oilfield services net margin	$ —	$ 115	$ 159
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 4.22	$ 4.69	$ 4.74
Oil, natural gas and NGL gathering, processing and transportation	$ 8.55	$ 8.43	$ 6.44
Production taxes	$ 0.40	$ 0.90	$ 0.94
General and administrative[(f)]	$ 0.95	$ 1.25	$ 1.86
Oil, natural gas and NGL depreciation, depletion and amortization	$ 8.47	$ 10.41	$ 10.59
Depreciation and amortization of other assets	$ 0.53	$ 0.90	$ 1.28
Interest expense[(g)]	$ 1.30	$ 0.63	$ 0.65
Interest Expense ($ in millions):			
Interest expense	$ 329	$ 173	$ 169
Interest rate derivatives – realized (gains) losses[(h)]	$ (6)	$ (12)	$ (9)
Interest rate derivatives – unrealized (gains) losses[(h)]	$ (6)	$ (72)	$ 67
Total interest expense	$ 317	$ 89	$ 227

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

(b) Beginning in the 2015 fourth quarter, we have reclassified our presentation of third party oil, natural gas and NGL gathering, processing and transportation costs to report the costs as a component of operating expenses in the accompanying statements of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales. The net effect of this reclassification did not impact our previously reported net income, stockholders' equity or cash flows; however, previously reported oil, natural gas and NGL sales and consequently total revenues have increased from the previously reported, and total operating expenses have increased by these same amounts. For additional information regarding this reclassification, see Note 1 of the notes to our consolidated financial statements included in Item 8 of this report.

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

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

(e) For the year ended December 31, 2015, we recorded unrealized gains of $296 million on the fair value of our supply contract derivatives. See Note 11 of the notes to our consolidated financial statements included in Item 8 of Part I of this report for discussion related to these instruments.

(f) Includes share-based compensation but excludes restructuring and other termination costs.

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

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

Overview

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

Operating Results

Our 2015 production of 248 mmboe consisted of 42 mmbbls of oil (17% on an oil equivalent basis), 1.1 tcf of natural gas (72% on an oil equivalent basis), and 28 mmbbls of NGL (11% on an oil equivalent basis). Our daily production for 2015 averaged approximately 679 mboe, a decrease of 4% from 2014. Compared to 2014, average daily oil production decreased by 2%, or approximately 2 mbbls per day; average daily natural gas production decreased by 2%, or approximately 69 mmcf per day; and average daily NGL production decreased by 15%, or approximately 14 mbbls per day. Our natural gas and NGL production decreased primarily as a result of the sales of certain of our Cleveland and Tonkawa assets in August 2015 and southern Marcellus Shale and Utica Shale assets in December 2014. In addition, our natural gas production decreased due to shut-in volume from our curtailment in the Marcellus and Utica Shales. Adjusted for asset sales, our total daily production increased 8% in 2015 compared to 2014. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $4.570 billion to $4.767 billion in 2015 compared to $9.336 billion in 2014, primarily due to significant decreases in the prices received for oil, natural gas and NGL sold. See *Results of Operations* below for additional details.

Capital Expenditures

Our drilling and completion capital expenditures during 2015 were approximately $3.0 billion and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $231 million, for a total of approximately $3.2 billion. In 2015, we operated an average of 28 rigs, a decrease of 36 rigs, or 56%, compared to 2014. As a result of lower drilling and completion activity, partially offset by a reduction in drilling carries received from our joint venture partners, drilling and completion expenditures decreased approximately $1.5 billion in 2015 compared to 2014. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $438 million compared to 2014. The reduction is primarily the result of the elimination of capital expenditures for our former oilfield services business which was spun off in June 2014. In 2014, we also purchased rigs and compressors previously sold under long-term lease arrangements for approximately $499 million as part of a strategic initiative to reduce complexity and future commitments as well as to facilitate asset sales and the spin-off of our oilfield services business. In 2014, we also invested approximately $450 million in our Powder River Basin Property exchange. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for details regarding the transaction.

Our capitalized interest was approximately $424 million and $637 million in 2015 and 2014, respectively. Including capitalized interest, total capital investments were approximately $3.6 billion in 2015 compared to $6.7 billion for 2014, a decrease of 46%.

Based on planned activity levels for 2016, we project that capital expenditures for drilling and completion, leasehold, geological and geophysical and other property and equipment will be $1.3 billion to $1.8 billion, inclusive of capitalized interest. The decrease from the $3.6 billion spent in 2015 is primarily driven by reduced activity as a result of continued lower forecasted oil and natural gas prices in 2016. See *Liquidity and Capital Resources* for additional information on how we plan to fund our capital budget.

Strategic Developments

Debt Exchanges and Repurchases

In November 2015, as required by the terms of the indenture for our 2.75% Contingent Convertible Senior Notes due 2035 (the 2035 Notes), each holder was provided the option to require us to purchase on November 15, 2015, all or a portion of such holder's 2035 Notes at par plus accrued and unpaid interest up to, but excluding, November 15, 2015. On November 16, 2015, we paid an aggregate of approximately $394 million to purchase the 2035 Notes that were tendered and not withdrawn.

In December 2015, we privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible notes (Existing Notes). Approximately $3.9 billion of the Existing Notes were exchanged for approximately $2.4 billion aggregate principal amount of the Second Lien Notes. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further details related to this exchange.

In December 2015, we repurchased in the open market approximately $119 million aggregate principal amount of our 3.25% Senior Notes due 2016 for $114 million.

Credit Facility Amendments

In September and December 2015, we amended our $4.0 billion senior revolving credit facility dated December 15, 2014, and maturing December 2019, which is used for general corporate purposes. Pursuant to the amended credit agreement, we are required to secure our obligations under the facility with liens on certain of our oil and natural gas properties, with such liens to be released upon the satisfaction of specific conditions. The amended credit facility provides that, while the obligations are required to be secured, (i) we have the right to incur junior lien indebtedness of up to $4.0 billion; (ii) our use of the facility will be subject to a borrowing base; (iii) the rate of interest on outstanding loans, as well as fees on undrawn commitments, will vary based on the percentage of the borrowing base used, rather than on our credit ratings; (iv) the total leverage ratio covenant will be suspended; and (v) the amended credit facility will be subject to a first lien secured leverage ratio and an interest coverage ratio. The permitted junior lien debt basket of $4.0 billion may be further increased upon the satisfaction of certain conditions, including the following: (i) after giving effect to all debt secured by such junior liens and the uses of such debt in retirement of other indebtedness, our net annual cash interest expense would increase by no more than $75 million, and (ii) we have exchanged debt secured by such junior liens for more than $2.0 billion aggregate principal amount of outstanding senior notes with maturities or initial put dates in 2017 through 2019. The amended credit facility requires us to maintain, as of the last day of each fiscal quarter while it is required to be secured by a portion of our oil and natural gas properties, (i) a first lien secured leverage ratio of no more than 3.5 to 1 through 2017 and 3.0 to 1.0 thereafter, and (ii) an interest rate coverage ratio of at least 1.1 to 1.0 through the first quarter of 2017, increasing to 1.25 to 1.0 by the end of 2017. The amendment sets the borrowing base at $4.0 billion. This amendment gives us greater flexibility and access to our liquidity.

Through the amendments discussed above, the total commitments under the credit facility remain at $4.0 billion, subject to reduction in connection with issuances of junior lien indebtedness by us after April 15, 2016, the date of the first borrowing base redetermination. No adjustment to the total commitment has occurred or will occur for any junior lien indebtedness issuance that occurs before April 15, 2016.

Workforce Reduction

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.

New Haynesville and Dry Gas Utica Gathering Agreements

In September 2015, we entered into new fixed-fee gas gathering agreements with subsidiaries of The Williams Companies, Inc. (Williams) in our Haynesville Shale operating area and our dry gas Utica Shale operating area. The fixed-fee provisions will be effective beginning in January 2016, replacing the previous fee structures that have applied. We expect that our gas gathering fees, when the new fee structure is effective, will be lower in both operating areas. Under the Haynesville Shale agreement, we expect to meet our existing minimum volume commitments (MVC) because of the consolidation of two Williams gathering systems and a projected increase in our Haynesville Shale volumes. Inclusive of previously expected MVC shortfall payments, we expect reductions in our Haynesville gas gathering rates of approximately $0.20 per mcf in 2016 and 2017 and approximately $0.30 per mcf in 2018 and beyond. Under the Utica Shale agreement, we estimate a gathering rate reduction of approximately $0.25 per mmbtu. We are dedicating an additional 50,000 net acres in the Utica Shale to Williams and will be subject to a new MVC of 250,000 mmbtu per day beginning in mid-2017. We expect to meet this Utica Shale MVC with approximately one rig per year.

Cleveland Tonkawa Transactions

On August 31, 2015, our subsidiary CHK C-T sold all of its oil and natural gas properties to FourPoint Energy, LLC (FourPoint) and immediately used the consideration received, plus other cash it had on hand, to repurchase and cancel all of CHK C-T's outstanding preferred shares. Chesapeake is responsible for post-closing adjustments to the purchase price and has certain indemnity obligations in connection with the sale to FourPoint. In connection with the repurchase and cancellation of the CHK C-T preferred stock and related agreements with the CHK C-T investors, we eliminated the noncontrolling interest and overriding royalty interest (ORRI) obligation on our consolidated balance sheet, $75 million in annual preferred dividend payments and all future drilling and ORRI commitments attributable to CHK C-T. Also on August 31, 2015, in a related transaction, we sold to FourPoint for approximately $90 million certain noncore properties adjacent to the CHK C-T properties. Chesapeake's net production from the assets sold in the two transactions was approximately 15 mboe per day in 2015. See Note 8 of the notes to our condensed consolidated financial statements included in Item 8 of this report for a description of CHK C-T.

2016 Developments

Subsequent to December 31, 2015, we repurchased in the open market approximately $60 million of our outstanding 2.5% Contingent Convertible Notes due 2037 for $32 million, $122 million of our 3.25% Senior Notes due 2016 for $115 million and $2 million of our 6.5% Senior Notes due 2017 for $1 million.

Subsequent to December 31, 2015, we amended certain of our firm transportation agreements in the Haynesville, Barnett and Eagle Ford operating areas which reduces our firm transportation volume commitments and fees described in Note 4 of the notes to our condensed consolidated financial statements included in Item 8 of this report. We estimate a benefit of approximately $650 million gross ($415 million net) over the term of the contracts, including $80 million gross ($50 million net) in lower unused demand charges for the underutilized capacity and lower transportation fees in 2016.

Subsequent to December 31, 2015, we closed certain asset divestitures for proceeds of approximately $138 million. We also executed sales agreements for other asset divestitures with expected proceeds of approximately $586 million. The asset divestitures cover various operating areas.

Liquidity and Capital Resources

Liquidity Overview

Chesapeake's strategy for 2016 is to focus on improving liquidity and generating cash. 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 recent substantial decline in oil, natural gas and NGL prices has negatively affected the amount of cash we have available for capital expenditures and debt service.

As of December 31, 2015, we had a cash balance of approximately $825 million and a net working capital deficit of approximately $1.205 billion. 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 budget, meet our debt service requirements and fund our other commitments and obligations for 2016. Oil and natural gas prices have a material impact on our financial position, results of operations, cash flows and quantities of oil, natural gas and NGL reserves that may be economically produced. If depressed prices persist throughout 2017 and we are unable to restructure or refinance our debt or generate additional liquidity through other actions, this would adversely impact our ability to comply with the financial covenants under our revolving credit facility and to make scheduled debt payments. To the extent that the value of the collateral pledged under the credit facility declines, we may be required to pledge additional collateral in order to maintain the availability of the commitments thereunder. In February 2016, our secured commodity hedging facility was terminated. This facility was collateralized with assets that are now unencumbered and for which we have the flexibility to pledge under our credit facility, if needed. Because of this additional unpledged collateral, we do not expect availability under our revolving credit facility to be materially reduced as a result of the next borrowing base redetermination in the 2016 second quarter. However, our borrowing base may be reduced as a result of oil and natural gas asset sales, a further decline in prices or other factors, some of which are outside of our control. See Note 3 and Note 11 of the notes to our consolidated financial statements included in Item 8 of this annual report for further discussion of the financial covenants in our revolving credit facility and for discussion of our secured commodity hedging facility, respectively.

As of December 31, 2015, we had approximately $9.706 billion principal amount of long-term debt outstanding, of which $381 million matures in March 2016, $1.892 billion matures or can be put to us in 2017 (of which $329 million matures in January 2017, $1.110 billion can be put to us in May 2017 and $453 million matures in August 2017) and $878 million matures or can be put to us in 2018. 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. We expect to draw on our revolving credit facility as early as the 2016 first quarter, primarily due to the principal payment to be made to retire our 3.25% Senior Notes due March 2016 and other 2016 first quarter cash needs. See Notes 3 and 4 of the notes to our consolidated financial statements included in Item 8 of this report for further details related to these items. We were undrawn on our revolving credit facility as of December 31, 2015.

As operator of a substantial portion of our oil and natural gas properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to reduce at least a portion of our capital spending as needed. We have reduced our budgeted 2016 capital expenditures, inclusive of capitalized interest, to $1.3 - $1.8 billion, a significant reduction from our 2015 capital spending level of $3.6 billion. We currently plan to use cash flow from operations, cash on hand and our revolving credit facility to fund our capital expenditures during 2016. We expect to generate additional liquidity with proceeds from potential sales of assets that we determine do not fit our strategic priorities. Management continues to review operational plans for 2016 and beyond, which could result in changes to projected capital expenditures and revenues from sales of oil, natural gas and NGL. We closely monitor the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our revolving credit facility.

Since December 2015, Moody's has lowered our senior unsecured credit rating from "Ba3" to "Caa3", and S&P has lowered our senior unsecured credit rating from "BB-" to "CC". Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as transportation, gathering, processing and hedging agreements. As of February 24, 2016, we have received requests to post approximately $220 million in collateral, of which we have posted approximately $92 million. We have posted the required collateral, primarily in the form of letters of credit and cash, or are otherwise complying with the contractual requests for collateral. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $698 million (excluding the supersedeas bond with respect to the 2019 Notes litigation discussed in Note 3 of the notes to our consolidated financial statements included in Item 8 of this report), which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business operations with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business commitments and by offsetting amounts that the counterparty owes us. Any posting of additional collateral consisting of cash or letters of credit, which would reduce availability under our credit facility, will negatively impact our liquidity.

In addition, during 2016, we may be required to pay up to $439 million in connection with the judgment against us related to the redemption at par value of our 6.775% Senior Notes due 2019. In connection with our appeal of the decision by the U.S. District Court for the Southern District of New York regarding the redemption, we posted a supersedeas bond in the amount of $461 million. For additional information, see Note 3 of the notes to our consolidated financial statements included in Item 8 of this report.

To supplement our cash flow from operations, we may seek to access the capital markets to refinance a portion of our outstanding indebtedness and improve our liquidity. We have historically used the debt capital markets, our most efficient method of raising capital, to supplement our liquidity needs. However, access to funds obtained through the high-yield debt market, particularly in the energy sector, has been severely constrained by a variety of market factors that could hinder our ability to raise new capital. We do not believe the high-yield debt market is currently accessible to us at favorable terms, and our accessibility may not improve during 2016.

We have taken a number of actions to improve our liquidity. We eliminated quarterly cash dividends on our common stock effective in the 2015 third quarter and suspended payment of dividends on our convertible preferred stock in the 2016 first quarter. In December 2015, we completed private exchanges of approximately $3.9 billion aggregate principal amount of long-term debt for approximately $2.4 billion aggregate principal amount of newly issued 8.00% Senior Secured Second Lien Notes due 2022. In September and December 2015, we amended our $4.0 billion revolving credit facility to provide more flexibility and access to liquidity. In September 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 August 2015, we closed the CHK C-T transactions described above in *Strategic Developments*. We terminated our secured hedge facility in February 2016 and are in the process of securing new hedges with the collateral for our revolving credit facility. The collateral for our recently terminated secured hedge facility is now available for other purposes, including additional collateral under our credit facility. We are also evaluating additional capital exchanges, asset sales, joint ventures and farmouts to increase our liquidity and cash flow. Finally, we recently restructured certain of our gathering agreements to improve our per-unit-gathering rates beginning in 2016, enhance volume growth and satisfy minimum volume commitment obligations.

To add more certainty to our future estimated cash flows by mitigating our downside exposure to lower commodity prices, as of February, 23, 2016, we have downside price protection, through open swaps, on approximately 56% of our projected 2016 oil production at an average price of $47.79 per bbl. We have downside price protection, through open swaps, on approximately 58% of our projected 2016 natural gas production at an average price of $2.84 per mcf. In addition, in exchange for a higher swap price, we have sold certain call options that allow the counterparty to double the notional amount on existing fixed-price swaps.

As highlighted above, we have taken measures to mitigate the liquidity concerns facing us in 2016 and beyond, but there can be no assurance that such measures, even if successfully implemented, will satisfy our needs. Further, our ability to generate operating cash flow in the current commodity price environment, sell assets, access capital markets or take any other action to improve our liquidity and manage our debt is subject to the risks discussed above and the other risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control. If commodity prices remain at depressed levels, or if we fail to complete significant asset sales, access the capital markets on favorable terms or take other actions to improve our liquidity, we may not be able to fund budgeted capital expenditures or meet our debt service requirements in 2017 and beyond.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the years ended December 31, 2015, 2014 and 2013. See Notes 12, 14 and 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of divestitures of oil and natural gas assets, investments and other assets, respectively.

	Years Ended December 31,		
	2015	2014	2013
		($ in millions)	
Cash Provided by Operating Activities	$ 1,234	$ 4,634	$ 4,614
Divestitures of Oil and Natural Gas Assets:			
Joint venture leasehold	33	33	58
Other oil and natural gas properties	156	5,780	3,409
Total divestitures of oil and natural gas assets	189	5,813	3,467
Sales of Other Assets:			
Compressors sold to ACMP	—	159	—
Compressors sold to Exterran	—	495	—
Sale of Mid-America Midstream Gas Services, L.L.C.	—	—	306
Sale of Granite Wash Midstream Gas Services, L.L.C.	—	—	252
Other property and equipment	89	349	364
Total sales of other assets	89	1,003	922
Other Sources of Cash and Cash Equivalents:			
Proceeds from sales of investments	—	239	115
Proceeds from long-term debt, net	—	2,966	2,274
Proceeds from oilfield services long-term debt, net	—	888	—
Other	52	37	187
Total other sources of cash and cash equivalents	52	4,130	2,576
Total sources of cash and cash equivalents	$ 1,564	$ 15,580	$ 11,579

Cash provided by operating activities was $1.234 billion in 2015 compared to $4.634 billion in 2014 and $4.614 billion in 2013. The decrease in cash provided by operating activities from 2015 to 2014 is primarily the result of lower realized prices for the oil, natural gas and NGL we sold, partially offset by realized gains on our derivative instruments and decreases in certain of our operating expenses. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, impairments, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See further discussion below under *Results of Operations*.

The following table reflects the proceeds received from issuances of debt in 2015, 2014 and 2013. 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,					
	2015		2014		2013	
	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds
	($ in millions)					
Senior notes[a]	$ —	$ —	$ 3,500	$ 3,460	$ 2,300	$ 2,274
Term loans[a]	—	—	400	394	—	—
Total	$ —	$ —	$ 3,900	$ 3,854	$ 2,300	$ 2,274

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

We currently plan to use cash flow from operations, cash on hand and our revolving credit facility to fund our capital expenditures during 2016. We expect to generate additional liquidity with proceeds from potential sales of assets that we have determined are non-core or do not fit our long-term plans. Prior to June 2014, we also utilized a $500 million oilfield services credit facility. This facility was terminated in June 2014 in connection with the spin-off of our oilfield services business. See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the spin-off. Under our revolving credit facilities, we had no borrowings or repayments in 2015, borrowed $7.406 billion and repaid $7.788 billion in 2014 and borrowed $7.669 billion and repaid $7.682 billion in 2013.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
Oil and Natural Gas Expenditures:			
Drilling and completion costs[(a)]	$ 3,083	$ 4,495	$ 5,490
Acquisitions of proved and unproved properties	123	758	302
Geological and geophysical cost	12	35	33
Interest capitalized on unproved properties	410	604	811
Total oil and natural gas expenditures	3,628	5,892	6,636
Other Uses of Cash and Cash Equivalents:			
Cash paid to repurchase debt	508	3,362	2,141
Cash paid to purchase leased rigs and compressors	—	499	240
Payments on credit facility borrowings, net	—	382	13
Additions to other property and equipment	143	227	732
Dividends paid	289	405	404
Distributions to noncontrolling interest owners	85	173	215
Cash paid to repurchase noncontrolling interest of CHK C-T [(b)]	143	—	—
Cash paid to repurchase preferred shares of CHK Utica[(b)]	—	1,254	212
Cash paid for financing derivatives[(c)]	—	53	91
Cash paid to extinguish other financing	—	—	141
Cash paid for prepayment of mortgage	—	—	55
Additions to investments	10	17	44
Other	41	45	105
Total other uses of cash and cash equivalents	1,219	6,417	4,393
Total uses of cash and cash equivalents	$ 4,847	$ 12,309	$ 11,029

(a) Net of $51 million, $679 million and $884 million in drilling and completion carries received from our joint venture partners during 2015, 2014 and 2013, respectively.

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

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

Our primary use of funds is for capital expenditures for drilling and completion costs on our oil and natural gas properties. During 2015, our average operated rig count was 28 rigs compared to an average operated rig count of 64 rigs in 2014 and 71 operated rigs in 2013. Although our average operated rig count decreased by 56% in 2015 compared to 2014, our drilling and completion expenditures did not decrease proportionately primarily as a result of a $628 million decrease in drilling and completion carries received from our joint venture partners.

Capital expenditures related to our midstream, oilfield services and other fixed assets were $143 million in 2015 compared to $227 million in 2014 and $732 million in 2013. The reduction of these expenditures in 2015 as compared to 2014 and 2013 is primarily the result of the spin-off of our oilfield services business in June 2014 and reductions in construction expenditures on our corporate headquarters and field offices.

In 2014 and 2013, we purchased rigs and compressors previously sold under long-term lease arrangements for approximately $499 million and $240 million, respectively, as part of a strategic initiative to reduce complexity and future commitments as well as to facilitate asset sales and the spin-off of our oilfield services business in June 2014.

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

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

In 2013, we used a portion of the net proceeds of $2.274 billion from senior notes offerings to repay outstanding indebtedness under our revolving credit facility and purchase certain senior notes. We purchased $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to tender offers during 2013. During 2013, we also redeemed $1.3 billion in aggregate principal amount of the 2019 Notes at par pursuant to notice of special early redemption. This redemption is subject to litigation. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for discussion of the litigation. On July 15, 2013, we retired at maturity the remaining $247 million aggregate principal amount outstanding of our 7.625% Senior Notes due 2013.

We paid dividends on our preferred stock of $171 million in each of 2015, 2014 and 2013. We paid dividends on our common stock of $118 million, $234 million and $233 million in 2015, 2014 and 2013, respectively. We eliminated common stock dividends effective in the 2015 third quarter and suspended preferred stock dividends effective in the 2016 first quarter.

Revolving Credit Facility

We have a $4.0 billion senior revolving credit facility that matures in December 2019. As of December 31, 2015, we had no outstanding borrowings under the facility and had used $16 million of the facility for various letters of credit. See *Liquidity Overview* above for additional information on our collateral postings. Borrowings under the facility bear interest at a variable rate. We are required to secure our obligations under the facility with liens on certain of our oil and natural gas properties, with such liens to be released upon the satisfaction of specific conditions. The applicable interest rates under the facility fluctuate based on the percentage of the borrowing base used. The financial covenants require us to maintain, as of the last day of each fiscal quarter, (i) a net debt to capitalization ratio (as defined in the amended credit agreement) that does not exceed 65%, and while the obligations are secured (a) a first lien secured leverage ratio (as defined in the amended credit agreement) of no more than 3.5 to 1.0 through 2017 and 3.0 to 1.0 thereafter and (b) and an interest rate coverage ratio (as defined in the amended credit agreement) of at least 1.1 to 1.0 through the first quarter of 2017, increasing to 1.25 to 1.0 by the end of 2017. As of December 31, 2015, our net debt to capitalization ratio was approximately 35%, our first lien secured leverage ratio was approximately 0.0 to 1.0 and our interest rate coverage ratio was approximately 3.13 to 1.0. As of December 31, 2015, we were in compliance with all financial covenants under the amended credit agreement. See Note 3 of the notes to our consolidated financial statements included in Item 8 of Part I for further discussion of the terms of the credit facility.

Hedging Arrangements

As of December 31, 2015, we had a multi-counterparty secured hedging facility with three counterparties that have committed to provide approximately 94 mmboe of hedging capacity for oil, natural gas and NGL price derivatives and 94 mmboe for basis derivatives with an aggregate mark-to-market capacity of $1.5 billion as of December 31, 2015. In February 2016, the hedging facility was terminated and all liens on the collateral securing the hedge facility were released. In April 2015, we also began using bilateral hedging agreements. For further discussion of the terms of the hedging facility and bilateral hedging agreements, see Note 11 of the notes to our consolidated financial statements included in Item 8 of this report.

Senior Note Obligations

Our senior note obligations consisted of the following as of December 31, 2015:

	December 31, 2015	
	Principal Amount	Carrying Amount
	($ in millions)	
3.25% senior notes due 2016	$ 381	$ 381
6.25% euro-denominated senior notes due 2017[a]	329	329
6.5% senior notes due 2017	453	452
7.25% senior notes due 2018	538	538
Floating rate senior notes due 2019	1,104	1,104
6.625% senior notes due 2020	822	822
6.875% senior notes due 2020	304	303
6.125% senior notes due 2021	589	589
5.375% senior notes due 2021	286	286
4.875% senior notes due 2022	639	639
8.00% senior secured second lien notes due 2022	2,425	3,584
5.75% senior notes due 2023	384	384
2.75% contingent convertible senior notes due 2035[b]	2	2
2.5% contingent convertible senior notes due 2037[b]	1,110	1,026
2.25% contingent convertible senior notes due 2038[b]	340	289
Interest rate derivatives[c]	—	7
Total senior notes, net	9,706	10,735
Less current maturities of long-term debt, net[d]	(381)	(381)
Total long-term senior notes, net	$ 9,325	$ 10,354

(a) The principal amount shown is based on the exchange rate of $1.0862 to €1.00 as of December 31, 2015. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for information on our related foreign currency derivatives.

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

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

(d) Current maturities of long-term debt, net includes the carrying amount of our 3.25% Senior Notes due March 2016.

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

Credit Risk

Derivative instruments that enable us to manage our exposure to oil, natural gas and NGL prices, as well as to interest rate and foreign currency volatility, expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2015, our oil, natural gas, interest rate and supply contract derivative instruments were spread among 16 counterparties. We also deposited available cash balances with many of these same counterparties as well as other relationship banks. Additionally, the counterparties under our commodity hedging arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($696 million as of December 31, 2015) and exploration and production companies that own interests in properties we operate ($230 million as of December 31, 2015). 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 which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2015, 2014 and 2013, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables. Additionally, during 2015, we recorded $22 million of impairment of a note receivable related to a previous asset sale as a result of the increased credit risk associated with declining commodity prices.

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to contractual obligations and off-balance sheet commitments. As of December 31, 2015, these arrangements and transactions included (i) operating lease agreements, (ii) volumetric production payments (VPPs) (to purchase production and pay related production expenses and taxes in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit, (vii) open gathering and transportation commitments, and (viii) various other commitments we enter into in the ordinary course of business that could result in a future cash obligation. See Notes 4 and 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of commitments and VPPs, respectively.

The table below summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2015.

	Payments Due By Period ($ in millions)				
	Total	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Long-term debt:					
Principal[a]	$ 9,706	$ 381	$ 2,770	$ 2,232	$ 4,323
Interest	3,417	540	994	808	1,075
Operating lease obligations[b]	9	4	4	1	—
Operating commitments[c]	14,431	2,215	3,869	2,554	5,793
Unrecognized tax benefits[d]	64	—	—	64	—
Standby letters of credit	16	16	—	—	—
Deferred premium on call options	87	87	—	—	—
Other	38	9	9	8	12
Total contractual cash obligations[e]	$ 27,768	$ 3,252	$ 7,646	$ 5,667	$ 11,203

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

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

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

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

(e) This table does not include derivative liabilities or the estimated discounted liability for future dismantlement, abandonment and restoration costs of oil and natural gas properties. See Notes 11 and 20, respectively, of the notes to our consolidated financial statements included in Item 8 of this report for more information on our derivatives and asset retirement obligations. This table also does not include our costs to produce reserves attributable to non-expense-bearing royalty and other interests in our properties, including VPPs, which are discussed below.

As the operator of the properties from which VPP volumes have been sold, we bear the cost of producing the reserves attributable to these interests, which we include as a component of production expenses and production taxes in our consolidated statements of operations in the periods these costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining our full cost ceiling test for impairment purposes and in determining our standardized measure. The amount of these VPP-related production expenses and taxes, based on cost levels as of December 31, 2015 pursuant to SEC reporting requirements, was estimated to be approximately $251 million in total and $67 million for the next twelve months on an undiscounted basis, and approximately $210 million and $63 million, respectively, on a discounted basis using an annual discount rate of 10%. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all. We have committed to purchase natural gas and liquids produced that are associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

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

Derivative Activities

Oil, Natural Gas and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the Company's derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading. As of December 31, 2015, our oil and natural gas derivative instruments consisted of swaps, options and basis protection swaps. Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* contains a description of each of these instruments and gains and losses on oil, natural gas and NGL derivatives during 2015, 2014 and 2013. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

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

Mark-to-market positions under commodity derivative contracts fluctuate with commodity prices. As described under *Hedging Facility* in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report, our secured multi-counterparty hedging facility allows us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of these derivatives by pledging our proved reserves.

The estimated fair values of our oil and natural gas derivative contracts as of December 31, 2015 and 2014 are provided below. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* for additional information concerning the fair value of our oil and natural gas derivative instruments.

	December 31,	
	2015	2014
	($ in millions)	
Derivative assets (liabilities):		
Oil fixed-price swaps	$ 144	$ 471
Oil three-way collars	—	40
Oil call options	(7)	(89)
Natural gas fixed-price swaps	229	281
Natural gas three-way collars	—	165
Natural gas call options	(99)	(170)
Natural gas basis protection swaps	—	23
Estimated fair value	$ 267	$ 721

Changes in the fair value of oil and natural gas derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of settled designated derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. As of December 31, 2015, 2014 and 2013, accumulated other comprehensive income included unrealized losses, net of related tax effects, totaling $113 million, $136 million and $159 million, respectively, associated with commodity derivative contracts. Based upon the market prices at December 31, 2015, we expect to transfer approximately $21 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. A detailed explanation of accounting for oil, natural gas and NGL derivatives appears under *Application of Critical Accounting Policies – Derivatives* elsewhere in this Item 7.

Interest Rate Derivatives

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

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

Gains or losses from interest rate derivative contracts are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2015, 2014 and 2013 are presented below in *Results of Operations – Interest Expense*, and a detailed explanation of accounting for interest rate derivatives appears under *Application of Critical Accounting Policies – Derivatives* elsewhere in this Item 7.

Foreign Currency Derivatives

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

Results of Operations

General. For the year ended December 31, 2015, Chesapeake had a net loss of $14.635 billion, or $22.43 per diluted common share, on total revenues of $12.764 billion. This compares to net income of $2.056 billion, or $1.87 per diluted common share, on total revenues of $23.125 billion for the year ended December 31, 2014 and net income of $894 million, or $0.73 per diluted common share, on total revenues of $19.080 billion for the year ended December 31, 2013. The decrease in net income in 2015 was primarily driven by impairments of our oil and natural gas properties. See *Impairment of Oil and Natural Gas Properties* below. The increase in net income in 2014 compared to 2013 was primarily driven by an increase in unrealized gains on our oil and natural gas derivative contracts as the future commodity prices moved lower. In addition, 2013 results include charges of approximately $546 million for the impairment of buildings, land, drilling rigs, gathering systems and other assets and $248 million related to restructuring and other termination costs incurred in connection with a workforce reduction, executive officer separations and other employee terminations. The charges reflect actions taken as a result of the company-wide review of our operations, assets and organizational structure in the second half of 2013. The decrease in total revenues in 2015 was primarily driven by decreases in the prices we received for our oil, natural gas and NGL production.

Oil, Natural Gas and NGL Sales. During 2015, oil, natural gas and NGL sales were $5.391 billion compared to $10.354 billion in 2014 and $8.626 billion in 2013. In 2015, Chesapeake sold 248 mmboe for $4.767 billion at a weighted average price of $19.23 per boe (excluding the effect of derivatives), compared to 258 mmboe sold in 2014 for $9.336 billion at a weighted average price of $36.21 per boe (excluding the effect of derivatives) and 244 mmboe sold in 2013 for $8.497 billion at a weighted average price of $34.77 (excluding the effect of derivatives). The decrease in the price received per boe in 2015 compared to 2014 resulted in a $4.211 billion decrease in revenues, and decreased sales volumes resulted in a $359 million decrease in revenues, for a total decrease in revenues of $4.570 billion (excluding the effect of derivatives). Previously, oil, natural gas and NGL gathering, processing and transportation expenses were reflected as deductions to oil, natural gas and NGL sales. Beginning in the 2015 fourth quarter, we have reclassified our presentation of these expenses to report such costs as a component of operating expenses in the accompanying statements of operations. See Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of this reclassification.

For 2015, our average price received per barrel of oil (excluding the effect of derivatives) was $45.77, compared to $89.41 in 2014 and $96.78 in 2013. Natural gas prices received per mcf (excluding the effect of derivatives) were $2.31, $4.14 and $3.44 in 2015, 2014 and 2013, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $14.06, $30.95 and $36.08 in 2015, 2014 and 2013, respectively.

Gains and losses from our oil and natural gas derivatives resulted in a net increase in oil, natural gas and NGL revenues of $624 million, $1.018 billion and $129 million in 2015, 2014 and 2013, respectively. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of this report for a complete listing of all of our derivative instruments as of December 31, 2015.

A change in oil, natural gas and NGL prices has a significant impact on our revenues and cash flows. Assuming our 2015 production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in 2015 revenues and cash flows of approximately $42 million and $40 million, respectively, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2015 revenues and cash flows of approximately $107 million and $106 million, respectively, and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease 2015 revenues and cash flows of $28 million.

The following tables show production and average sales prices received by our operating divisions for 2015, 2014 and 2013:

2015

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

2014

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

2013

	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[(a)]	(bcf)	($/mcf)[(a)]	(mmbbl)	($/bbl)[(a)]	(mmboe)	%	($/boe)[(a)]
Southern[(b)] ..	37.6	97.30	692.9	3.42	16.7	33.15	169.7	69	38.85
Northern[(c)] ...	3.5	91.17	401.7	3.47	4.2	47.65	74.7	31	25.63
Total......	41.1	96.78	1,094.6	3.44	20.9	36.08	244.4	100%	34.77

(a) Average sales prices exclude gains (losses) on derivatives. The decrease in the average sales price for our oil sold in 2015 as compared to 2014 and 2013 was primarily driven by lower crude oil prices. The decrease in the average sales price for our natural gas sold in 2015 as compared to 2014 was primarily driven by lower natural gas prices. The decrease in the average sales price for our NGL sold in 2015 as compared to 2014 and 2013 was primarily driven by a decrease in ethane and propane prices due to seasonality in the Utica Shale play.

(b) Our Southern Division includes the Eagle Ford and Anadarko Basin liquids plays and the Haynesville/Bossier and Barnett natural gas shale plays. The Eagle Ford Shale accounted for approximately 24% of our estimated proved reserves by volume as of December 31, 2015. Eagle Ford Shale production for 2015, 2014 and 2013 was 38.5 mmboe, 35.4 mmboe and 31.7 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara liquids plays and the Marcellus natural gas play. The Utica Shale accounted for approximately 18% of our estimated proved reserves by volume as of December 31, 2015. Utica Shale production for 2015, 2014 and 2013 was 43.8 mmboe, 26.6 mmboe and 7.5 mmboe, respectively. The Marcellus Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2015. Marcellus Shale production for 2015, 2014 and 2013 was 49.7 mmboe, 74.7 mmboe and 62.9 mmboe, respectively.

Our average daily production of 679 mboe for 2015 consisted of approximately 114,000 bbls of oil (17% on an oil equivalent basis), approximately 2.9 bcf of natural gas (72% on an oil equivalent basis) and approximately 76,700 bbls of NGL (11% on an oil equivalent basis). Oil production decreased by 2% year over year, natural gas production decreased by 2% and NGL production decreased by 15%.

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

	Years Ended December 31,		
	2015	**2014**	**2013**
Oil	40%	40%	47%
Natural gas	52%	49%	44%
NGL	8%	11%	9%
Total	100%	100%	100%

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses and exclude depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our marketing, gathering and compression assets. Chesapeake recognized $7.373 billion in marketing, gathering and compression revenues in 2015, of which $296 million related to unrealized gains on the fair value of our supply contract derivatives, with corresponding expenses of $7.130 billion, for a net margin before depreciation of $243 million. This compares to revenues of $12.225 billion, expenses of $12.236 billion and a net loss before depreciation of $11 million in 2014 and revenues of $9.559 billion, expenses of $9.461 billion and a net margin before depreciation of $98 million in 2013. Revenues and expenses decreased in 2015 compared to 2014 and 2013 primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations. The margin increase in 2015 as compared to 2014 and 2013 was primarily the result of an unrealized gain on the fair value adjustment on our supply contract derivatives, partially offset by cost increases on certain sales contracts with third parties entered into to help meet certain of our oil pipeline and other commitments and by lower compression margin as a result of the sale of a significant portion of our compression assets in 2014 and 2015.

Oilfield Services Revenues and Expenses. Our oilfield services consisted of third-party revenues and expenses related to our former oilfield services operations and excluded depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See *Depreciation and Amortization of Other Assets* below for the depreciation and amortization recorded on our oilfield services assets in 2014. Chesapeake recognized revenues of $546 million and $895 million, expenses of $431 million and $736 million with a net margin before depreciation of $115 million and $159 million in 2014 and 2013. As a result of the spin-off of our oilfield services business in June 2014, we did not have oilfield services revenues and expenses in 2015 and will not have oilfield services revenues and expenses in future periods.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $1.046 billion in 2015, compared to $1.208 billion in the 2014 and $1.159 billion in 2013. On a unit-of-production basis, production expenses were $4.22 per boe in 2015 compared to $4.69 per boe in 2014 and $4.74 in 2013. The per unit decrease in 2015 was primarily the result of operating efficiencies across most of our operating areas. Production expenses in 2015, 2014 and 2013 included approximately $104 million, $157 million and $177 million, or $0.42, $0.61 and $0.72 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease and operating efficiencies generally improve. In addition, our obligations with respect to two of our VPPs were assumed by third parties as a result of our divestiture of related properties in 2014 and another VPP expired in 2015.

The following table shows our production expenses (excluding ad valorem taxes) by operating division and our ad valorem tax expenses for 2015, 2014 and 2013:

	2015		2014		2013	
	Production Expenses	$/boe	Production Expenses	$/boe	Production Expenses	$/boe
	($ in millions, except per unit)					
Southern[(a)]	$ 771	5.36	$ 882	5.92	$ 925	5.46
Northern	188	1.81	229	2.10	164	2.19
	959	3.87	1,111	4.31	1,089	4.46
Ad valorem tax	87	0.35	97	0.38	70	0.28
Total	$ 1,046	4.22	$ 1,208	4.69	$ 1,159	4.74

(a) The per unit increase in the Southern Division from 2013 to 2014 is primarily the result of increased artificial lift, repairs and maintenance and a higher percentage of oil produced which has higher lifting costs.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $2.119 billion in 2015 compared to $2.174 billion in 2014 and $1.574 billion in 2013. On a unit-of-production basis, gathering, processing and transportation expenses were $8.55 per boe in 2015 compared to $8.43 per boe in 2014 and $6.44 per boe in 2013. Certain of our gathering agreements require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. These fees amounted to $171 million in 2015, $120 million in 2014 and $42 million in 2013, or $0.69, $0.47 and $0.17 per boe, respectively, and we anticipate incurring shortfall fees in 2016 based on current production estimates. Previously, these costs were reflected as a deduction to oil, natural gas and NGL sales. See Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of this reclassification.

Production Taxes. Production taxes were $99 million in 2015 compared to $232 million in 2014 and $229 million in 2013. On a unit-of-production basis, production taxes were $0.40 per boe in 2015 compared to $0.90 per boe in 2014 and $0.94 per boe in 2013. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in 2015 was primarily due to lower prices received for oil, natural gas and NGL. Production taxes in 2015, 2014 and 2013 included approximately $2 million, $16 million and $22 million, or a nominal amount, $0.06 and $0.09 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production tax expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease. In addition, our obligations with respect to two of our VPPs were assumed by third parties as a result of our divestiture of related properties in 2014 and another VPP expired in 2015.

General and Administrative Expenses. General and administrative expenses, including share-based compensation expenses, were $235 million in 2015, $322 million in 2014 and $457 million in 2013, or $0.95, $1.25 and $1.86 per boe, respectively. The absolute and per unit expense decrease in 2015 was primarily due to reduced overhead as a result of the spin-off of our oilfield services business in June 2014, our workforce reduction in the 2015 third quarter and our continuing efforts to reduce other administrative expenses. In addition, in 2015, we recorded negative fair value adjustments to PSUs granted to executives of the Company, which corresponded to a decrease in the trading price of our common stock. The absolute and per unit expense decrease in 2014 was primarily due to our workforce reduction in the second half of 2013 as well as efforts to reduce other administrative expenses. See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our share-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $196 million, $230 million and $317 million of internal costs in 2015, 2014 and 2013, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded expense of $36 million, $7 million and $248 million in 2015, 2014 and 2013, respectively, related to restructuring and other termination costs. In 2015, we reduced our workforce by approximately 15% as part of an overall plan to reduce costs and better align our workforce with the needs of our business and current oil and natural gas commodity prices. In connection with the reduction, we incurred a total charge of approximately $55 million in 2015 for one-time termination benefits, all of which were paid in cash in the fourth quarter of 2015. Additionally, the 2015 and 2014 amounts include 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. The 2014 expense also includes charges incurred in connection with the spin-off of our oilfield services business and senior management separations. The Company committed to a workforce reduction plan in September 2013 that resulted in a reduction of approximately 900 employees. In connection with the workforce reduction plan, we incurred a total charge of $66 million. The acceleration of vesting of stock-based compensation accounted for approximately $45 million of this expense. We also incurred charges of approximately $182 million in 2013 related to the separation from the Company of certain other employees, including approximately $107 million related to our former CEO and other executive officers that were outside the workforce reduction plan. See Note 18 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our restructuring and other termination costs.

Provision for Legal Contingencies. In 2015 and 2014, respectively, we recorded $353 million and $234 million for legal contingencies. The 2015 provision consisted of $25 million related to the April 2015 resolution of litigation we were defending against the state of Michigan and $339 million related to litigation involving our early redemption of our 2019 Notes. See Notes 3 and 4 of the notes to our consolidated financial statements included in Item 8 of this report for discussion of ongoing 2019 Notes litigation. Additionally in 2015, we reduced our royalty provision amount from $119 million to $109 million to reflect the amount paid in 2015 to settle litigation with Oklahoma royalty owners, net of claimants that opted-out. In 2014, we accrued $134 million of loss contingencies related to royalty claims. See Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of royalty claims. In 2014, we also accrued a $100 million loss contingency for litigation regarding our 2019 Notes litigation.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $2.099 billion, $2.683 billion and $2.589 billion in 2015, 2014 and 2013, respectively. The average DD&A rate per boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $8.47, $10.41 and $10.59 in 2015, 2014 and 2013, respectively. The absolute and per unit decrease in 2015 was the result of a lower amortization base as a result of our impairment of oil and gas properties in 2015 and a reduction in our estimated future development costs as a result of drilling efficiencies and a forecasted reduction in our future capital plans, partially offset by an approximate 39% reduction in our reserve base driven primarily by lower prices used in calculating our estimated reserves. Approximately 46% of the reduction in our reserves base due to price was associated with proved undeveloped reserves. The $94 million increase in 2014 was primarily driven by increases in our production.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $130 million in 2015 compared to $232 million in 2014 and $314 million in 2013. On a unit-of-production basis, depreciation and amortization of other assets was $0.53 per boe in 2015 compared to $0.90 per boe in 2014 and $1.28 in 2013. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. In June 2014, we completed the spin-off of our oilfield services business and, therefore, did not incur oilfield services depreciation expense in 2015 and will not incur this expense in future periods. In 2014, to the extent company-owned oilfield services equipment was used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) was capitalized in oil and natural gas properties as drilling and completion costs. The following table shows depreciation expense by asset class for 2015, 2014 and 2013 and the estimated useful lives of these assets.

	Years Ended December 31,			Estimated Useful Life
	2015	2014	2013	
		($ in millions)		(in years)
Natural gas compressors[a]	$ 38	$ 37	$ 35	3 – 20
Buildings and improvements	39	42	47	10 – 39
Computers and office equipment	22	32	44	3 – 7
Vehicles	10	24	38	0 – 7
Natural gas gathering systems and treating plants[a]	11	12	13	20
Oilfield services equipment[b]	—	74	122	3 – 15
Other	10	11	15	2 – 20
Total depreciation and amortization of other assets	$ 130	$ 232	$ 314	

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

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

Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. Throughout 2015, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments of the carrying value of our oil and natural gas properties totaling $18.238 billion. Cash flow hedges as of December 31, 2015, which relate to future periods, increased the ceiling test impairment by $176 million.

As of December 31, 2015, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $4.727 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of December 31, 2015 were $50.28 per bbl of oil and $2.58 per mcf of natural gas, before price differential adjustments. Based on first-of-the-month index prices for January and February 2016, as well as the current strip prices for March 2016, we reasonably expect a decrease of approximately $4.50 per barrel of oil and $0.15 per mcf of natural gas in the prices we will be using to calculate the estimated future net revenue of our proved reserves as of March 31, 2016, and such decreases are expected to reduce the present value of estimated future net revenue of our proved reserves by approximately $1.2 billion in the 2016 first quarter. Such decrease is likely to be a significant factor in the amount of impairment recorded for the quarter ending March 31, 2016. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

Deterioration in commodity prices also impacts estimated quantities of proved reserves. In 2015, we recognized negative reserve revisions to our year-end 2014 estimated proved reserves of approximately 44% due to lower commodity prices. Based on first-of-the-month index prices for January and February 2016, as well as the current strip prices for March 2016, we reasonably expect negative price-related revisions to our March 31, 2016 estimated proved reserves of approximately 8%, and if prices continue to decline we expect to have additional negative price-related revisions in the future. We do not expect these negative price-related revisions and 2016 production to be fully offset by reserve additions.

Impairments of Fixed Assets and Other. In 2015, 2014 and 2013, we recognized $194 million, $88 million and $546 million, respectively, of fixed asset impairment losses and other charges. The 2015 amount consisted of a $70 million charge for a joint venture net acreage shortfall with Total, a $47 million loss contingency related to contract disputes, a $21 million impairment related to the sale of third-party rental compressors, a $22 million impairment of a note receivable and $18 million of charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices. Further contract termination charges in subsequent quarters may occur if commodity prices remain low. The 2014 amount consisted of a $22 million charge for our Barnett Shale joint venture net acreage shortfall with Total and $64 million of impairments related to a gathering system, drilling rigs, natural gas compressors and buildings and land. The 2013 amount relates to impairments of certain of our gathering systems and treating plants, drilling rigs, buildings and land, a gas gathering termination fee and a contract drilling agreement termination fee. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairments of fixed assets and other.

Net (Gains) Losses on Sales of Fixed Assets. In 2015, net losses on sales of fixed assets were $4 million compared to net gains of $199 million and $302 million in 2014 and 2013, respectively. The 2015 amount primarily related to the sale of buildings and land and gathering systems. The 2014 amount primarily related to the sale of natural gas compressors and crude hauling assets. The 2013 amount primarily related to the sale of certain of our midstream gathering systems. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our net gains on sales of fixed assets.

Interest Expense. Interest expense was $317 million in 2015 compared to $89 million in 2014 and $227 million in 2013 as follows:

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
Interest expense on senior notes	$ 682	$ 704	$ 740
Interest expense on term loan	—	36	116
Amortization of loan discount, issuance costs and other	59	42	91
Interest expense on credit facilities	12	28	38
Realized gains on interest rate derivatives[(a)]	(6)	(12)	(9)
Unrealized gains on interest rate derivatives[(b)]	(6)	(72)	67
Capitalized interest	(424)	(637)	(816)
Total interest expense	$ 317	$ 89	$ 227
Average senior notes borrowings	$ 11,705	$ 11,653	$ 10,991
Average term loan borrowings	$ —	$ 625	$ 2,000
Average credit facilities borrowings	$ —	$ 306	$ 678

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

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

The increase in 2015 interest expense was primarily due to a decrease in capitalized interest and a decrease in unrealized gains on interest rate derivatives, partially offset by a decrease in senior note, term loan and credit facility interest expense. The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. The decrease in 2014 interest expense was primarily due to a decrease in interest expense on our senior notes and term loans as a result of our debt refinancing in April 2014, the elimination of debt related to the spin-off of our oilfield services business and unrealized gains on interest rate derivatives, partially offset by a decrease in the amount of interest capitalized as a result of a lower average balance of unevaluated oil and natural gas properties, the primary asset on which interest is capitalized. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our debt refinancing. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.30 per boe in 2015 compared to $0.63 per boe in 2014 and $0.65 in 2013.

Losses on Investments. Losses on investments were $96 million in 2015 compared to $75 million in 2014 and $216 million in 2013. Losses in 2015 and 2014 were primarily related to our equity in FTS International, Inc. and Sundrop Fuels, Inc. Losses in 2013 primarily relate to our equity in the net loss of FTS and Sundrop, offset by our equity in the net income of Chaparral Energy, Inc. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

Impairments of Investments. In 2015, 2014 and 2013, we recognized impairments of investments of $53 million, $5 million and $10 million. The 2015 amount consisted of an other-than-temporary impairment of our FTS investment due to the extended decrease in the oil and natural gas pricing environment. The 2014 and 2013 amounts related to other miscellaneous investments. See Note 14 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of our investments.

Net Gain (Loss) on Sales of Investments. We recorded a net gain on sales of investments of $67 million in 2014 compared to net losses of $7 million in 2013. In 2014, we sold all of our interest in Chaparral Energy, Inc. for net cash proceeds of $209 million and recorded a $73 million gain related to the sale. In addition, we sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million and recorded a loss of $6 million associated with the transaction. In 2013, we sold all of our shares of Clean Energy Fuels Corp. (Clean Energy) for cash proceeds of $13 million and recorded a $3 million gain related to the sale. We also sold our $100 million investment in Clean Energy convertible notes for cash proceeds of $85 million and recorded a $15 million loss related to the sale. In addition, in 2013 we sold a $1 million equity investment for cash proceeds of $6 million and recorded a $5 million gain.

*Gains (Losses) on Purchases or Exchanges of Deb*t. In 2015, we recorded a gain of $279 million on purchases of debt and we recorded losses on purchases of debt of $197 million in 2014 and $193 million in 2013.

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 10 of the 12 series of notes exchanged, we are accounting for these exchanges as a trouble debt restructuring (“TDR”). For exchanges classified as TDR, if the future undiscounted cash flows of the newly issued debt are less than the net carrying value of the original debt, a gain is recorded for the difference and the carrying value of the newly issued debt is adjusted to the future undiscounted cash flow amount and no interest expense is recorded going forward. For the remaining TDR exchanges, where the future undiscounted cash flows are greater than the net carrying value of the original debt, no gain is recognized and a new effective interest rate is established. Accordingly, we recognized a gain of $304 million in our consolidated statement of operations. Direct costs incurred for $29 million related to the notes exchange were also recognized. Additionally, we purchased in the open market approximately $119 million aggregate principal amount of our 3.25% Senior Notes due 2016 for cash. We recorded a gain of approximately $5 million associated with the repurchase.

In December 2014, we entered into a new five-year $4.0 billion senior unsecured revolving credit facility to use for general corporate purposes. That credit facility replaced our then-existing $4.0 billion senior secured revolving credit facility that was scheduled to mature in December 2015. We recognized a loss of approximately $2 million in extinguishment costs related to lenders under the terminated facility that were not lenders under the new facility. In 2014, we repaid the borrowings under and terminated our $2.0 billion term loan credit facility due 2017 and recorded a loss of approximately $90 million, including $40 million in premiums, $30 million of unamortized discount and $20 million of unamortized deferred charges. Also in 2014, we purchased and redeemed $1.265 billion in aggregate principal amount of our 9.5% Senior Notes due 2015. We recorded a loss of approximately $99 million associated with the purchase and redemption, including $87 million in premiums, $9 million of unamortized debt discount and $3 million of unamortized deferred charges. In addition, in 2014, we redeemed $97 million in principal amount of our 6.875% Senior Notes due 2018 at par. We recorded a loss of approximately $6 million associated with the redemption, including $5 million in premiums and $1 million of unamortized deferred charges.

In 2013, we terminated the financing master lease agreement on our real estate surface properties in the Fort Worth, Texas area for $258 million and recorded a loss of approximately $123 million associated with the extinguishment. Also, in 2013, we completed tender offers to purchase $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million. We recorded a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million of unamortized deferred charges. In addition, we redeemed $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 at par pursuant to a notice of special early redemption. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount.

Other Income. Other income was $8 million in 2015, compared to $22 million in 2014 and $26 million in 2013. The 2015 income consisted of $6 million of interest income and $2 million of miscellaneous income. The 2014 other income consisted primarily of $3 million of interest income and $19 million of miscellaneous income. The 2013 other income consisted of $5 million of interest income and $21 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $4.463 billion in 2015 and income tax expense of $1.144 billion and $548 million in 2014 and 2013, respectively. Our effective income tax rate was 23.4% in 2015, 35.8% in 2014 and 38.0% in 2013. The decrease in the effective income tax rate from 2014 to 2015 is primarily due to the tax benefit at expected rates being offset by a significant increase in our valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of income tax expense (benefit).

Based on the material write-downs of the carrying value of our oil and natural gas properties and our operating results for the year ending December 31, 2015, we are in a net deferred tax asset position at year end. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated was the cumulative loss incurred over the three-year period ending December 31, 2015. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased, or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $50 million, $139 million and $170 million in 2015, 2014 and 2013, respectively. Net income attributable to noncontrolling interests in 2015 consisted of income related to the Chesapeake Granite Wash Trust and dividends paid on preferred stock of our CHK C-T subsidiary. The 2014 and 2013 amounts included income related to the Chesapeake Granite Wash Trust as well as dividends paid on preferred stock of our CHK C-T and CHK Utica subsidiaries. The decreases from 2014 to 2015 and from 2013 to 2014 are primarily due to the repurchase of all of the outstanding preferred shares of CHK Utica and CHK C-T from third-party preferred shareholders in July 2014 and August 2015, respectively. See Note 8 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of these entities.

Application of Critical Accounting Policies

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

The selection and application of accounting policies are an important process that changes as our business changes and as accounting rules are developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment in the specific set of circumstances existing in our business.

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

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

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

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

Two primary factors impacting this test are reserve levels and oil and natural gas prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of oil and natural gas reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. See *Oil and Natural Gas Properties* in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further information on the full cost method of accounting.

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

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

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Additionally, in accordance with accounting guidance for derivatives and hedging, to the extent that a legal right of set-off exists, we net the value of our derivative instruments with the same counterparty in the accompanying consolidated balance sheets.

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

Due to the volatility of oil, natural gas and NGL prices and, to a lesser extent, interest rates and foreign exchange rates, the Company's financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2015, 2014 and 2013, the fair values of our derivatives were net assets of $512 million, net assets of $652 million and net liabilities of $649 million, respectively.

Income Taxes. The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of both federal and state taxing jurisdictions. Income taxes are accounted for using the asset and liability approach. The Company has recognized deferred tax assets and liabilities for temporary differences between tax and book basis, tax credit carryforwards and net operating loss carryforwards. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider the preponderance of evidence concerning the realization of the deferred tax asset. Among the more significant types of evidence that we consider are:

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

Our judgments and assumptions in estimating future taxable income include such factors as future operating conditions and commodity prices. As of December 31, 2015 and 2014, we had deferred tax assets of $4.119 billion and $1.667 billion, respectively, upon which we had a valuation allowance of $2.949 billion and $222 million, respectively. The valuation allowance as of December 31, 2015 was recorded against our net deferred tax asset and as of December 31, 2014 was recorded for certain state net operating losses and tax credits. We have concluded that these deferred tax assets are not more likely than not to be realized.

The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest related to these uncertain tax positions which is recognized in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. Additional information about uncertain tax positions appears in Note 6 of the notes to our consolidated financial statements included in Item 8 of this report.

Disclosures About Effects of Transactions with Related Parties

Our equity method investees are considered related parties. See Note 7 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of transactions with our equity method investees.

Forward-Looking Statements

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

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

- the volatility of oil, natural gas and NGL prices;
- write-downs of our oil and natural gas asset carrying values due to declines in prices;
- the availability of operating cash flow and other funds to finance reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- commodity derivative activities resulting in lower prices realized on oil, natural gas and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- the limitations our level of indebtedness may have on our financial flexibility;
- charges incurred in response to market conditions and in connection with our ongoing actions to reduce financial leverage and complexity;
- drilling and operating risks and resulting liabilities;
- effects of environmental protection laws and regulation on our business;
- legislative and regulatory initiatives further regulating hydraulic fracturing;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- federal and state tax proposals affecting our industry;
- potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations;
- impacts of potential legislative and regulatory actions addressing climate change;
- competition in the oil and gas exploration and production industry;
- a deterioration in general economic, business or industry conditions;
- negative public perceptions of our industry;
- limited control over properties we do not operate;
- pipeline and gathering system capacity constraints and transportation interruptions;
- cyber-attacks adversely impacting our operations;
- an interruption in operations at our headquarters due to a catastrophic event;
- our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means; and
- our inability to access the capital markets on favorable terms or at all.

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

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

Oil, Natural Gas and NGL Derivatives

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

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

We use derivative instruments to achieve our risk management objectives, including swaps and options. All of these are described in more detail below. We typically use swaps 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. In 2012 and 2013, we bought oil and natural gas calls to, in effect, lock in sold call positions. Due to lower oil, natural gas and NGL prices, we were able to achieve this at a low cost to us. In some cases, we deferred the payment of the premium on these trades to the related month of production. Some of our derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception and the cash settlements associated with these instruments are classified as financing cash flows in the accompanying consolidated statements of cash flows.

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

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

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

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

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

As of December 31, 2015, we had the following open oil and natural gas derivative instruments:

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps[(a)]:						
Short-term	13.5	$ 52.05	$ —	$ —	$ —	$ 144
Call Options (sold):						
Short-term	13.9	—	87.25	—	—	(4)
Long-term	5.3	—	83.50	—	—	(3)
Total Oil						$ 137

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(tbtu)	($ per mmbtu)				($ in millions)
Natural Gas:						
Swaps[(b)]:						
Short-term	500	$ 2.94	$ —	$ —	$ —	$ 229
Call Options (sold):						
Short-term	381	—	5.66	—	—	(14)
Long-term	114	—	10.92	—	—	—
Call Options (bought)[(c)]:						
Short-term	(200)	—	6.02	—	—	(85)
Basis Protection Swaps:						
Short-term	33	—	—	—	0.17	6
Long-term	24	—	—	—	(0.48)	(6)
Total Natural Gas						$ 130
Total Oil and Natural Gas						$ 267

(a) Certain hedging arrangements include a sold option to double the volume at an average price of $53.67/bbl covering 2.9 mmbbls, which are included in the sold call options.

(b) Certain hedging arrangements include a sold option to double the volume at an average price of $2.80/mmbtu covering 102 tbtus, which are included in the sold call options.

(c) Included in the fair value are deferred premiums of $86 million which will be included in oil, natural gas and NGL sales as realized gains (losses) in 2016.

In addition to the open derivative positions disclosed above, as of December 31, 2015, we had $15 million of net derivative gains related to settled contracts for future production periods that will be recorded within oil, natural gas and NGL sales as realized gains (losses) on derivatives once they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production, based on the terms specified in the original contract as noted below.

	December 31, 2015
	($ in millions)
Short-term	$ 14
Long-term	1
Total	$ 15

The table below reconciles the changes in fair value of our oil and natural gas derivatives during the year ended December 31, 2015. Of the $267 million fair value asset as of December 31, 2015, a $276 million asset relates to contracts maturing in the next 12 months and a $9 million liability relates to contracts maturing after 12 months. All open derivative instruments as of December 31, 2015 are expected to mature by December 31, 2022.

	December 31, 2015
	($ in millions)
Fair value of contracts outstanding, as of January 1	$ 721
Change in fair value of contracts	661
Contracts realized or otherwise settled	(1,117)
Fair value of contracts closed	2
Fair value of contracts outstanding, as of December 31	$ 267

The change in oil and natural gas prices during 2015 increased the asset related to our derivative instruments by $661 million. This unrealized gain is recorded in oil, natural gas and NGL sales. We settled contracts in 2015 that were in an asset position for $1.117 billion. We terminated contracts that were in a liability position for $2 million. Realized gains and losses will be recorded in oil, natural gas and NGL sales in the month of related production.

Interest Rate Derivatives

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates, using the earliest demand repurchase date for contingent convertible senior notes. As of December 31, 2015, we had total debt of $9.7 billion, including $8.6 billion of fixed rate debt at interest rates averaging 5.94% and $1.1 billion of floating rate debt at an interest rate of 3.57% (three-month LIBOR plus 3.25%).

	Years of Maturity						
	2016	2017	2018	2019	2020	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$ 381	$ 1,892	$ 878	$ —	$ 1,128	$ 4,323	$ 8,602
Average interest rate	3.25%	4.11%	5.31%	—%	6.69%	6.91%	5.94%
Debt – variable rate	$ —	$ —	$ —	$ 1,104	$ —	$ —	$ 1,104
Average interest rate	—%	—%	—%	3.57%	—%	—%	3.57%

(a) This amount does not include the premium included in debt of $1.022 billion and interest rate derivatives of $7 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving credit facility 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, 2015, there were no interest rate derivatives outstanding.

As of December 31, 2015, we had $39 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 eight-year term of our related senior notes.

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

Foreign Currency Derivatives

In December 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. In December 2015, we exchanged and subsequently retired €42 million in aggregate principal amount of these senior notes, and we simultaneously unwound the cross currency swaps for the same principal amount. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €9 million and we pay the counterparties $15 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €302 million and we will pay the counterparties $403 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the consolidated balance sheets as liabilities of $52 million and $53 million as of December 31, 2015 and 2014, respectively. The euro-denominated debt in long-term debt has been adjusted to $329 million as of December 31, 2015, using an exchange rate of $1.0862 to €1.00.

Supply Contract Derivatives

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

ITEM 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS
CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in 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, 2015.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015 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 25, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Chesapeake Energy Corporation

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries (the "Company") at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 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, 2015, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it presents deferred income tax assets and liabilities in 2015.

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 25, 2016

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$ 825	$ 4,108
Restricted cash	—	38
Accounts receivable, net	1,129	2,236
Short-term derivative assets ($0 and $16 attributable to our VIE)	366	879
Other current assets	160	207
Total Current Assets	2,480	7,468
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)	63,843	58,594
Unproved properties	6,798	9,788
Other property and equipment	2,927	3,083
Total Property and Equipment, at Cost	73,568	71,465
Less: accumulated depreciation, depletion and amortization (($428) and ($251) attributable to our VIE)	(59,365)	(39,043)
Property and equipment held for sale, net	95	93
Total Property and Equipment, Net	14,298	32,515
LONG-TERM ASSETS:		
Investments	136	265
Long-term derivative assets	246	6
Other long-term assets	197	497
TOTAL ASSETS	$ 17,357	$ 40,751

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

	December 31, 2015	December 31, 2014
CURRENT LIABILITIES:		
Accounts payable	$ 944	$ 2,049
Current maturities of long-term debt, net	381	381
Accrued interest	101	150
Short-term derivative liabilities	40	15
Other current liabilities ($8 and $15 attributable to our VIE)	2,219	3,061
Total Current Liabilities	3,685	5,656
LONG-TERM LIABILITIES:		
Long-term debt, net	10,354	11,154
Deferred income tax liabilities	—	4,392
Long-term derivative liabilities	60	218
Asset retirement obligations, net of current portion	452	447
Other long-term liabilities	409	679
Total Long-Term Liabilities	11,275	16,890
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,251,515 shares outstanding	3,062	3,062
Common stock, $0.01 par value, 1,000,000,000 shares authorized: 664,795,509 and 664,944,232 shares issued	7	7
Paid-in capital	12,403	12,531
Retained earnings (accumulated deficit)	(13,202)	1,483
Accumulated other comprehensive loss	(99)	(143)
Less: treasury stock, at cost; 1,437,724 and 1,614,312 common shares	(33)	(37)
Total Chesapeake Stockholders' Equity	2,138	16,903
Noncontrolling interests	259	1,302
Total Equity	2,397	18,205
TOTAL LIABILITIES AND EQUITY	$ 17,357	$ 40,751

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2015	2014	2013
	($ in millions except per share data)		
REVENUES:			
Oil, natural gas and NGL	$ 5,391	$ 10,354	$ 8,626
Marketing, gathering and compression	7,373	12,225	9,559
Oilfield services	—	546	895
Total Revenues	12,764	23,125	19,080
OPERATING EXPENSES:			
Oil, natural gas and NGL production	1,046	1,208	1,159
Oil, natural gas and NGL gathering, processing and transportation	2,119	2,174	1,574
Production taxes	99	232	229
Marketing, gathering and compression	7,130	12,236	9,461
Oilfield services	—	431	736
General and administrative	235	322	457
Restructuring and other termination costs	36	7	248
Provision for legal contingencies	353	234	—
Oil, natural gas and NGL depreciation, depletion and amortization	2,099	2,683	2,589
Depreciation and amortization of other assets	130	232	314
Impairment of oil and natural gas properties	18,238	—	—
Impairments of fixed assets and other	194	88	546
Net (gains) losses on sales of fixed assets	4	(199)	(302)
Total Operating Expenses	31,683	19,648	17,011
INCOME (LOSS) FROM OPERATIONS	(18,919)	3,477	2,069
OTHER INCOME (EXPENSE):			
Interest expense	(317)	(89)	(227)
Losses on investments	(96)	(75)	(216)
Impairments of investments	(53)	(5)	(10)
Net gain (loss) on sales of investments	—	67	(7)
Gains (losses) on purchases or exchanges of debt	279	(197)	(193)
Other income	8	22	26
Total Other Expense	(179)	(277)	(627)
INCOME (LOSS) BEFORE INCOME TAXES	(19,098)	3,200	1,442
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	(36)	47	22
Deferred income taxes	(4,427)	1,097	526
Total Income Tax Expense (Benefit)	(4,463)	1,144	548
NET INCOME (LOSS)	(14,635)	2,056	894
Net income attributable to noncontrolling interests	(50)	(139)	(170)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(14,685)	1,917	724
Preferred stock dividends	(171)	(171)	(171)
Repurchase of preferred shares of CHK Utica	—	(447)	(69)
Earnings allocated to participating securities	—	(26)	(10)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (14,856)	$ 1,273	$ 474
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ (22.43)	$ 1.93	$ 0.73
Diluted	$ (22.43)	$ 1.87	$ 0.73
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.0875	$ 0.35	$ 0.35
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	662	659	653
Diluted	662	772	653

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,		
	2015	2014	2013
	($ in millions)		
NET INCOME (LOSS)	$ (14,635)	$ 2,056	$ 894
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Unrealized gains (losses) on derivative instruments, net of income tax expense (benefit) of $12, $0, and $1	20	1	2
Reclassification of (gains) losses on settled derivative instruments, net of income tax expense (benefit) of $15, $14 and $12	24	23	20
Unrealized loss on investments, net of income tax benefit of $0, $0 and ($4)	—	—	(6)
Reclassification of (gains) losses on investment, net of income tax expense (benefit) of $0, ($3) and $3	—	(5)	4
Other Comprehensive Income (Loss)	44	19	20
COMPREHENSIVE INCOME (LOSS)	(14,591)	2,075	914
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(50)	(139)	(170)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (14,641)	$ 1,936	$ 744

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,		
	2015	2014	2013
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ (14,635)	$ 2,056	$ 894
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	2,229	2,915	2,903
Deferred income tax expense (benefit)	(4,427)	1,097	526
Derivative gains, net	(932)	(1,102)	(71)
Cash receipts (payments) on derivative settlements, net	1,123	(253)	(104)
Stock-based compensation	78	59	98
Impairment of oil and natural gas properties	18,238	—	—
Net (gains) losses on sales of fixed assets	4	(199)	(302)
Impairments of fixed assets and other	175	58	483
Losses on investments	96	75	219
Impairments of investments	53	5	10
Net (gains) losses on sales of investments	—	(67)	7
(Gains) losses on purchases or exchanges of debt	(304)	63	40
Restructuring and other termination costs	(14)	(15)	175
Provision for legal contingencies	340	234	—
Other	244	220	122
(Increase) decrease in accounts receivable and other assets	1,186	(21)	5
Decrease in accounts payable, accrued liabilities and other	(2,220)	(491)	(391)
Net Cash Provided By Operating Activities	1,234	4,634	4,614
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(3,095)	(4,581)	(5,604)
Acquisitions of proved and unproved properties	(533)	(1,311)	(1,032)
Proceeds from divestitures of proved and unproved properties	189	5,813	3,467
Additions to other property and equipment	(143)	(726)	(972)
Proceeds from sales of other property and equipment	89	1,003	922
Additions to investments	(10)	(17)	(44)
Proceeds from sales of investments	—	239	115
Decrease in restricted cash	52	37	177
Other	—	(3)	4
Net Cash Provided By (Used In) Investing Activities	(3,451)	454	(2,967)

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

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

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	—	7,406	7,669
Payments on credit facilities borrowings	—	(7,788)	(7,682)
Proceeds from issuance of senior notes, net of discount and offering costs	—	2,966	2,274
Proceeds from issuance of oilfield services senior notes, net of discount and offering costs	—	494	—
Proceeds from issuance of oilfield services term loan, net of issuance costs	—	394	—
Cash paid to purchase debt	(508)	(3,362)	(2,141)
Cash paid for common stock dividends	(118)	(234)	(233)
Cash paid for preferred stock dividends	(171)	(171)	(171)
Cash paid on financing derivatives	—	(53)	(91)
Cash paid to repurchase noncontrolling interest of CHK C-T	(143)	—	—
Cash paid to repurchase preferred shares of CHK Utica	—	(1,254)	(212)
Cash held and retained by SSE at spin-off	—	(8)	—
Cash paid to extinguish other financing	—	—	(141)
Cash paid for prepayment of mortgage	—	—	(55)
Distributions to noncontrolling interest owners	(85)	(173)	(215)
Proceeds from sales of noncontrolling interests	—	—	6
Other	(41)	(34)	(105)
Net Cash Used In Financing Activities	(1,066)	(1,817)	(1,097)
Net increase (decrease) in cash and cash equivalents	(3,283)	3,271	550
Cash and cash equivalents, beginning of period	4,108	837	287
Cash and cash equivalents, end of period	$ 825	$ 4,108	$ 837

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

	2015	2014	2013
SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest paid, net of capitalized interest	$ 235	$ 96	$ 43
Income taxes paid, net of refunds received	$ 44	$ 10	$ 26
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Repurchase of noncontrolling interest of CHK C-T	$ (872)	$ —	$ —
Divestiture of proved and unproved CHK C-T properties	$ 1,024	$ —	$ —
Change in divested proved and unproved properties	$ 35	$ 38	$ (104)
Change in accrued drilling and completion costs	$ (148)	$ (84)	$ (63)
Change in accrued acquisitions of proved and unproved properties	$ 55	$ (74)	$ (1)

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,		
	2015	2014	2013
	($ in millions)		
PREFERRED STOCK:			
Balance, beginning and end of period	$ 3,062	$ 3,062	$ 3,062
COMMON STOCK:			
Balance, beginning and end of period	7	7	7
PAID-IN CAPITAL:			
Balance, beginning of period	12,531	12,446	12,293
Stock-based compensation	71	47	162
Exercise of stock options	—	23	4
Dividends on common stock	(59)	—	—
Dividends on preferred stock	(128)	—	—
Increase (decrease) in tax benefit from stock-based compensation	(12)	15	(13)
Balance, end of period	12,403	12,531	12,446
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance, beginning of period	1,483	688	437
Net income (loss) attributable to Chesapeake	(14,685)	1,917	724
Dividends on common stock	—	(234)	(233)
Dividends on preferred stock	—	(171)	(171)
Spin-off of oilfield services business	—	(270)	—
Repurchase of preferred shares of CHK Utica	—	(447)	(69)
Balance, end of period	(13,202)	1,483	688
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(143)	(162)	(182)
Hedging activity	44	24	22
Investment activity	—	(5)	(2)
Balance, end of period	(99)	(143)	(162)
TREASURY STOCK – COMMON:			
Balance, beginning of period	(37)	(46)	(48)
Purchase of 54,493, 34,678 and 251,403 shares for company benefit plans	(1)	(1)	(6)
Release of 231,081, 422,395 and 397,098 shares from company benefit plans	5	10	8
Balance, end of period	(33)	(37)	(46)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	2,138	16,903	15,995
NONCONTROLLING INTERESTS:			
Balance, beginning of period	1,302	2,145	2,327
Net income attributable to noncontrolling interests	50	139	170
Distributions to noncontrolling interest owners	(78)	(169)	(215)
Repurchase of noncontrolling interest of CHK C-T	(1,015)	—	—
Repurchase of preferred shares of CHK Utica	—	(807)	(143)
Sales of noncontrolling interests	—	—	6
Deconsolidation of investments, net	—	(6)	—
Balance, end of period	259	1,302	2,145
TOTAL EQUITY	$ 2,397	$ 18,205	$ 18,140

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation ("Chesapeake" or the "Company") is an oil and natural gas exploration and production company engaged in the acquisition, exploration and development of properties for the production of oil, natural gas and natural gas liquids (NGL) from underground reservoirs. We also own oil and natural gas marketing and natural gas gathering and compression businesses, and prior to June 30, 2014, an oilfield services business (see Note 13). Our operations are located onshore in the United States.

Basis of Presentation

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

Accounting Estimates

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

Estimates of oil and natural gas reserves and their values, future production rates and future costs and expenses are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in oil, natural gas or NGL prices could result in actual results differing significantly from our estimates.

Risks and Uncertainties

Chesapeake’s strategy for 2016 is to focus on improving liquidity and generating cash. 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 recent substantial decline in oil, natural gas and NGL prices has negatively affected the amount of cash we have available for capital expenditures and debt service.

Throughout 2015, our capitalized costs of oil and natural gas properties exceeded our full cost ceiling, resulting in a noncash impairment in the carrying value of our oil and natural gas properties of $18.238 billion, which was the primary driver of our net loss in 2015 of $14.635 billion. Based on first-of-the-month index prices over the 11 months ended February 1, 2016, we expect to record additional downward reserve revisions and another material write-down in the carrying value of our oil and natural gas properties in the first quarter of 2016. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

As of December 31, 2015, we had a cash balance of approximately $825 million and a net working capital deficit of $1.205 billion. 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 budget, meet our debt service requirements, and fund our other commitments and obligations for 2016. Oil and natural gas prices have a material impact on our financial position, results of operations, cash flows and quantities of oil, natural gas and NGL reserves that may be economically produced. If depressed prices persist throughout 2017 and we are unable to restructure or refinance our debt or generate additional liquidity through other actions, this would adversely impact our ability to comply with the financial covenants under our revolving credit facility and to make scheduled debt payments. To the extent that the value of the collateral pledged under the credit facility declines, we may be required to pledge additional collateral in order to maintain the availability of the commitments thereunder. In February 2016, our secured commodity hedging facility was terminated. This facility was collateralized with assets that are now unencumbered and for which we have the flexibility to pledge under our credit facility, if needed. Because of this additional unpledged collateral, we do not expect availability under our revolving credit facility to be materially reduced as a result of the next borrowing base redetermination in the 2016 second quarter. However, our borrowing base may be reduced as a result of oil and natural gas asset sales, a further decline in prices or other factors, some of which are outside of our control. See Note 3 and Note 11 for further discussion of the financial covenants in our revolving credit facility and for discussion of our secured commodity hedging facility, respectively.

As of December 31, 2015, we had approximately $9.706 billion principal amount of long-term debt outstanding, of which $381 million matures in March 2016, $1.892 billion matures or can be put to us in 2017 (of which $329 million matures in January 2017 and the remainder matures or can be put to us after the 2017 first quarter) and $878 million matures or can be put to us in 2018. See Note 3 for further discussion of our debt obligations, including principal and carrying amounts of our notes. We expect to draw on our revolving credit facility as early as the 2016 first quarter primarily due to the principal payment to be made to retire our 3.25% Senior Notes due March 2016 and other 2016 first quarter cash needs. We were undrawn on our revolving credit facility as of December 31, 2015.

As operator of a substantial portion of our oil and natural gas properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to reduce at least a portion of our capital spending as needed. We have reduced our budgeted 2016 capital expenditures, inclusive of capitalized interest, to $1.3 - $1.8 billion, a significant reduction from our 2015 capital spending level of $3.6 billion. We currently plan to use cash flow from operations, cash on hand and our revolving credit facility to fund our capital expenditures during 2016. We expect to generate additional liquidity with proceeds from potential sales of assets that we determine do not fit our strategic priorities. Management continues to review operational plans for 2016 and beyond, which could result in changes to projected capital expenditures and revenues from sales of oil, natural gas and NGL. We closely monitor the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our revolving credit facility.

Since December 2015, Moody's Investor Services, Inc. has lowered our senior unsecured credit rating from "Ba3" to "Caa3", and Standard & Poor's Rating Services has lowered our senior unsecured credit rating from "BB-" to "CC". Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as transportation, gathering, processing and hedging agreements. As of February 24, 2016, we have received requests to post approximately $220 million in collateral, of which we have posted approximately $92 million. We have posted the required collateral, primarily in the form of letters of credit and cash, or are otherwise complying with these contractual requests for collateral. We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $698 million (excluding the supersedeas bond with respect to the 2019 Notes litigation discussed in Note 3), which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business operations with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business commitments and by offsetting amounts that the counterparty owes us. Any posting of additional collateral consisting of cash or letters of credit, which would reduce availability under our credit facility, will negatively impact our liquidity.

To supplement our cash flow from operations, we may seek to access the capital markets to refinance a portion of our outstanding indebtedness and improve our liquidity. We have historically used the debt capital markets, our most efficient method of raising capital, to supplement our liquidity needs. However, access to funds obtained through the high-yield debt market, particularly in the energy sector, has been severely constrained by a variety of market factors that could hinder our ability to raise new capital. We do not believe the high-yield debt market is currently accessible to us at favorable terms, and our accessibility may not improve during 2016.

We have taken a number of actions to improve our liquidity. We eliminated quarterly cash dividends on our common stock effective in the 2015 third quarter and suspended payment of dividends on our convertible preferred stock in the 2016 first quarter. In December 2015, we completed private exchanges of approximately $3.9 billion aggregate principal amount of long-term debt for approximately $2.4 billion aggregate principal amount of newly issued 8.00% Senior Secured Second Lien Notes due 2022. In September and December 2015, we amended our $4.0 billion revolving credit facility to provide more flexibility and access to liquidity. In September 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 August 2015, we closed the CHK C-T transactions described in Note 8. We terminated our secured hedge facility in February 2016 and are in the process of securing new hedges with the collateral for our revolving credit facility. The collateral for our recently terminated secured hedge facility is now available for other purposes, including additional collateral under our credit facility. We are also evaluating additional capital exchanges, asset sales, joint ventures and farmouts to increase our liquidity and cash flow. Finally, we recently restructured certain of our gathering agreements to improve our per-unit-gathering rates beginning in 2016, enhance volume growth and satisfy minimum volume commitment obligations.

As highlighted above, we have taken measures to mitigate the risks and uncertainties facing us in 2016, including mitigating a portion of our downside exposure to lower commodity prices through derivative contracts, but there can be no assurance that such measures, even if successfully implemented, will satisfy our needs. Further, our ability to generate operating cash flow in the current commodity price environment, sell assets, access capital markets or take any other action to improve our liquidity and manage our debt is subject to the risks discussed above and the other risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control. If commodity prices remain at depressed levels, or if we fail to complete significant asset sales, access the capital markets on favorable terms or take other actions to improve our liquidity, we may not be able to fund budgeted capital expenditures or meet our debt service requirements in 2017 or beyond.

Consolidation

Chesapeake consolidates entities in which we have a controlling financial interest. We consolidate subsidiaries in which we hold, directly or indirectly, more than 50% of the voting rights and variable interest entities (VIEs) in which Chesapeake is the primary beneficiary. We use the equity method of accounting to record our net interests where Chesapeake has the ability to exercise significant influence through its investment. Under the equity method, our share of net income (loss) is included in our consolidated statements of operations according to our equity ownership or according to the terms of the applicable governing instrument. Investments in securities not accounted for under the equity method have been designated as available-for-sale and, as such, are carried at fair value whenever this value is readily determinable. Otherwise, the investment is carried at cost. See Note 14 for further discussion of our investments. Undivided interests in oil and natural gas exploration and production joint ventures are consolidated on a proportionate basis.

Noncontrolling Interests

Noncontrolling interests represent third-party equity ownership in certain of our consolidated subsidiaries and are presented as a component of equity. See Note 8 for further discussion of noncontrolling interests.

Variable Interest Entities

VIEs are entities that, by design, either (i) lack sufficient equity to permit the entity to finance its activities independently, or (ii) have equity holders that do not have the power to direct the activities of the entity that most significantly impact its economic performance, the obligation to absorb the entity's losses, or the right to receive the entity's residual returns. We consolidate a VIE when we are the primary beneficiary, which is the party that has both (i) the power to direct the activities that most significantly impact the VIE's economic performance and (ii) through its interests in the VIE, the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

Along with a VIE that we consolidate, we also hold a variable interest in another VIE that is not consolidated because we are not the primary beneficiary. We continually monitor both our consolidated and unconsolidated VIEs to determine if any reconsideration events have occurred that could cause the primary beneficiary to change. See Note 15 for further discussion of VIEs.

Cash and Cash Equivalents and Restricted Cash

For purposes of the consolidated financial statements, Chesapeake considers investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents. As of December 31, 2014, our restricted cash consisted of the balance required to be maintained by the terms of the agreement governing the activities of CHK Cleveland Tonkawa, L.L.C. (CHK C-T). The repurchase and cancellation of the outstanding preferred shares of CHK C-T eliminated the restricted cash maintenance requirement related to this entity. See Note 8 for further discussion.

Accounts Receivable

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL and from exploration and production companies that own interests in properties we operate. This industry concentration could affect our overall exposure to credit risk, either positively or negatively, because our purchasers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties and we generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. We utilize an allowance method in accounting for bad debt based on historical trends in addition to specifically identifying receivables that we believe may be uncollectible. During 2015, 2014 and 2013, we recognized $4 million, $2 million and $2 million of bad debt expense related to potentially uncollectible receivables. Accounts receivable as of December 31, 2015 and 2014 are detailed below.

	December 31,	
	2015	2014
	($ in millions)	
Oil, natural gas and NGL sales	$ 696	$ 1,340
Joint interest	230	691
Other	226	226
Allowance for doubtful accounts	(23)	(21)
Total accounts receivable, net	$ 1,129	$ 2,236

Oil and Natural Gas Properties

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with these activities and do not capitalize any costs related to production, general corporate overhead or similar activities (see *Supplementary Information – Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities*). Capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. Estimates of our proved reserves as of December 31, 2015 were prepared by independent engineering firms and Chesapeake's internal staff. Approximately 59% by volume and 77% by value of these proved reserves estimates as of December 31, 2015 were prepared by independent engineering firms. 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 where individual property costs are not significant. In addition, we analyze our unproved leasehold and transfer to proved properties that portion of our leasehold which can be associated with proved reserves, leasehold that expired in the quarter or leasehold that is not a 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, 2015 and the year in which the associated costs were incurred.

	Year of Acquisition				
	2015	2014	2013	Prior	Total
	($ in millions)				
Leasehold cost	$ 121	$ 651	$ 200	$ 4,304	$ 5,276
Exploration cost	68	13	15	58	154
Capitalized interest	331	303	259	475	1,368
Total	$ 520	$ 967	$ 474	$ 4,837	$ 6,798

We also review, on a quarterly basis, the carrying value of our oil and natural gas properties under the full cost accounting rules of the Securities and Exchange Commission (SEC). This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for oil and natural gas derivatives designated as cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. The ceiling test calculation uses costs as of the end of the applicable quarterly period and the unweighted arithmetic average of oil, natural gas and NGL prices on the first day of each month within the 12-month period prior to the ending date of the quarterly period. These prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives designated as cash flow hedges. As of December 31, 2015, none of our open derivative instruments were designated as cash flow hedges. Our oil and natural gas hedging activities are discussed in Note 11.

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

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

Other Property and Equipment

Other property and equipment consists primarily of natural gas compressors, buildings and improvements, land, vehicles, computer and office equipment, oil and natural gas gathering systems and treating plants. We have no remaining oilfield services equipment as a result of the spin-off of our oilfield services business in 2014, as discussed in Note 13. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operating costs. See Note 16 for further discussion of our gains and losses on the sales of other property and equipment for the years ended 2015, 2014 and 2013 and a summary of our other property and equipment held for sale as of December 31, 2015 and 2014. 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 disposal value, if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets and discounted cash flow. During 2015, 2014 and 2013, we determined that certain of our property and equipment was being carried at values that were not recoverable and in excess of fair value. See Note 17 for further discussion of these impairments.

Capitalized Interest

Interest from external borrowings is capitalized on significant 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, 2015 and 2014 are liabilities of approximately $60 million and $333 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 and Hedging Facility Costs

Included in other long-term assets are costs associated with the issuance of our senior notes, revolving credit facility and hedging facility. The remaining unamortized issuance costs as of December 31, 2015 and 2014 totaled $74 million and $130 million, respectively, and are being amortized over the life of the applicable debt instrument or credit facility using the effective interest method.

Environmental Remediation Costs

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

Asset Retirement Obligations

We recognize liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For oil and natural gas properties, this is the period in which an oil or natural gas well is acquired or drilled. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our oil and natural gas properties. See Note 20 for further discussion of asset retirement obligations.

Revenue Recognition

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

Natural Gas Imbalances. We follow the sales method of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net liability position as of December 31, 2015 and 2014 was $10 million and $12 million, respectively.

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

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

Fair Value Measurements

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

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

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

Derivatives

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

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

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

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

Share-Based Compensation

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

To the extent compensation expense relates to employees directly involved in the acquisition of oil and natural gas leasehold and exploration and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses, oil, natural gas and NGL production expenses, or marketing, gathering and compression expenses, based on the employees involved in those activities.

Cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock are classified as financing cash inflows, while reductions in tax benefits are classified as operating cash outflows in our consolidated statements of cash flows. See Note 9 for further discussion of share-based compensation.

Reclassifications

Certain reclassifications have been made to our consolidated financial statements for 2014 and 2013 to conform to the presentation used for the 2015 consolidated financial statements. Beginning in the fourth quarter of 2015, we have reclassified our presentation of third party transportation and gathering costs to report the costs as a component of operating expenses in the accompanying statements of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales. The net effect of this reclassification did not impact our previously reported net income, stockholders' equity or cash flows; however, previously reported oil, natural gas and NGL sales have increased from the amounts previously reported, and total operating expenses have increased by those same amounts. The following table reflects the reclassifications made:

	Years Ended December 31, 2014	Years Ended December 31, 2013
	$ in millions	
Oil, natural gas and NGL sales, previously reported	$ 8,180	$ 7,052
Reclassification of oil, natural gas and NGL gathering, processing and transportation expenses	2,174	1,574
Oil, natural gas and NGL sales, as currently reported	$ 10,354	$ 8,626

The corresponding amounts have been reflected in oil, natural gas and NGL gathering, processing and transportation expenses for 2014 and 2013 as shown below:

	Years Ended December 31, 2014	Years Ended December 31, 2013
	$ in millions	
Oil, natural gas and NGL gathering, processing and transportation expenses, previously reported	$ —	$ —
Reclassification of oil, natural gas and NGL gathering, processing and transportation expenses	2,174	1,574
Oil, natural gas and NGL gathering, processing and transportation expenses, as currently reported	$ 2,174	$ 1,574

In November 2015, the FASB issued an accounting standards update, which requires deferred tax liabilities and assets be classified as non-current in a classified statement of financial position. This standards update is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2016. Early adoption is permitted and we elected to adopt the updated standard effective December 31, 2015. This change in accounting principle is preferable since the current presentation does not generally align with the time period in which the deferred tax amounts are expected to be recognized. A retrospective change to the December 31, 2014 consolidated balance sheet as previously presented is required pursuant to this updated standard. We retrospectively adjusted the December 31, 2014 consolidated balance sheet and reclassified $207 million of our current deferred income tax liabilities to noncurrent deferred income tax liabilities.

2. Earnings Per Share

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

Diluted EPS is calculated assuming the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For the years ended December 31, 2015, 2014 and 2013, 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 contingent convertible senior notes.

For the years ended December 31, 2015, 2014 and 2013, shares of the following securities and associated adjustments to net income, representing dividends on preferred stock and allocated earnings on participating securities, were excluded from the calculation of diluted EPS as the effect was antidilutive.

	Net Income Adjustments	Shares
	($ in millions)	(in millions)
Year Ended December 31, 2015		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 86	59
5.75% cumulative convertible preferred stock (series A)	$ 63	42
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	6
4.50% cumulative convertible preferred stock	$ 12	6
Participating securities	$ —	1
Year Ended December 31, 2014		
Participating securities	$ 26	3
Year Ended December 31, 2013		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 86	56
5.75% cumulative convertible preferred stock (series A)	$ 63	40
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	5
4.50% cumulative convertible preferred stock	$ 12	6
Participating securities	$ 10	5

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

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

3. Debt

Our long-term debt consisted of the following as of December 31, 2015 and 2014:

	December 31, 2015		December 31, 2014	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
3.25% senior notes due 2016	$ 381	$ 381	$ 500	$ 500
6.25% euro-denominated senior notes due 2017[a][b]	329	329	416	416
6.5% senior notes due 2017[b]	453	452	660	659
7.25% senior notes due 2018[b]	538	538	669	669
Floating rate senior notes due 2019[b]	1,104	1,104	1,500	1,500
6.625% senior notes due 2020[b]	822	822	1,300	1,300
6.875% senior notes due 2020[b]	304	303	500	497
6.125% senior notes due 2021[b]	589	589	1,000	1,000
5.375% senior notes due 2021[b]	286	286	700	700
4.875% senior notes due 2022[b]	639	639	1,500	1,500
8.00% senior secured second lien notes due 2022[b]	2,425	3,584	—	—
5.75% senior notes due 2023[b]	384	384	1,100	1,100
2.75% contingent convertible senior notes due 2035[c][d]	2	2	396	381
2.5% contingent convertible senior notes due 2037[b][c][d]	1,110	1,026	1,168	1,024
2.25% contingent convertible senior notes due 2038[b][c][d]	340	289	347	279
Revolving credit facility	—	—	—	—
Interest rate derivatives[e]	—	7	—	10
Total debt, net	9,706	10,735	11,756	11,535
Less current maturities of long-term debt, net[f]	(381)	(381)	(396)	(381)
Total long-term debt, net	$ 9,325	$ 10,354	$ 11,360	$ 11,154

(a) The principal amount shown is based on the exchange rate of $1.0862 to €1.00 and $1.2098 to €1.00 as of December 31, 2015 and 2014, respectively. See *Foreign Currency Derivatives* in Note 11 for information on our related foreign currency derivatives.

(b) In 2015, a portion of these outstanding senior unsecured notes were exchanged for newly issued 8.00% Senior Secured Second Lien Notes due 2022. See *Chesapeake Senior Secured Second Lien Notes* and *Chesapeake Senior Notes and Contingent Convertible Senior Notes* below for further discussion regarding these transactions.

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

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

Optional Conversion by Holders. At the holder's option, prior to maturity under certain circumstances, the notes are convertible into cash and, if applicable, shares of our common stock using a net share settlement process. One triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. During the specified period in the fourth quarter of 2015, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes and, as a result, the holders do not have the option to convert their notes into cash and common stock in the first quarter of 2016 under this provision.

The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. The notes were not convertible under this provision during the years ended December 31, 2015, 2014 or 2013. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of the principal amount.

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

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

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

Optional Redemption by the Company. We may redeem the contingent convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash.

(d) Discount as of December 31, 2015 and 2014 included $133 million and $224 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

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

(f) As of December 31, 2015, current maturities of long-term debt, net includes the carrying amount of our 3.25% Senior Notes due March 2016. As of December 31, 2014, there was $15 million of discount associated with the equity component of the 2.75% Contingent Convertible Senior Notes due 2035. As discussed in footnote (c) above, holders of our 2.75% Contingent Convertible Senior Notes due 2035 exercised their demand repurchase rights on November 15, 2015, which required us to repurchase such holders' notes.

Total principal amount of debt maturities, using the earliest demand repurchase date for contingent convertible senior notes, for the five years ended after December 31, 2015 and thereafter are as follows:

	Principal Amount of Debt Securities
	($ in millions)
2016	$ 381
2017	1,892
2018	878
2019	1,104
2020	1,128
2021 and thereafter	4,323
Total	$ 9,706

Chesapeake Senior Secured Second Lien Notes

In December 2015, we completed private offers to exchange newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible senior notes (Existing Notes). Approximately $3.929 billion aggregate principal amount of the Existing Notes were exchanged. The Second Lien Notes are secured second lien obligations and are effectively junior to our current and future secured first lien indebtedness, including indebtedness incurred under our revolving credit facility, to the extent of the value of the collateral securing such indebtedness, effectively senior to all of our existing and future unsecured indebtedness, including our outstanding senior notes, to the extent of the value of the collateral, and senior to any future subordinated indebtedness that we may incur. We have the option to redeem the Second Lien Notes, in whole or in part, at specified make-whole or redemption prices. Our Second Lien Notes are governed by an indenture containing covenants that may limit our ability and our subsidiaries' ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, consolidate, merge or transfer assets and dispose of certain collateral and use proceeds from dispositions of certain collateral. As a holding company, Chesapeake owns no operating assets and has no significant operations independent of its subsidiaries. Chesapeake's obligations under the Second Lien Notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries. See Note 22 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

For 10 of the 12 series of Existing Notes (with a carrying value of $3.679 billion) that were exchanged for $2.219 billion of Second Lien Notes, we accounted for these exchanges as a troubled debt restructuring ("TDR"). For the exchanges classified as TDR, if the future undiscounted cash flows of the newly issued debt are less than the net carrying value of the original debt, a gain is recorded for the difference and the carrying value of the newly issued debt is adjusted to the future undiscounted cash flow amount and no future interest expense is recorded. All future interest payments on the newly issued debt reduce the carrying value. Accordingly, we recognized a gain of $304 million in our consolidated statement of operations, and the remaining reduction in principal amount of Existing Notes of $1.159 billion is included in the carrying value of our Second Lien Notes. As a result, our reported interest expense will be significantly less than the contractual interest payments throughout the term of the Second Lien Notes. For the remaining TDR exchanges, where the future undiscounted cash flows are greater than the net carrying value of the original debt, no gain is recognized and a new effective interest rate is established. For the other two series of Existing Notes that were exchanged and did not qualify as a TDR, we accounted for these exchanges as either a modification or extinguishment. Direct costs incurred of $30 million related to the notes exchange were expensed and are included within gains (losses) on purchases or exchanges of debt in our consolidated statement of operations.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

The Chesapeake senior notes and the 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. Chesapeake's 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 22 for consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

We may redeem the senior notes, other than the contingent 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 contingent convertible senior notes do not have any financial or restricted payment covenants. Indentures for the Second Lien Notes, senior notes and contingent convertible senior notes have cross default provisions that apply to other indebtedness the Company or any guarantor subsidiary may have from time to time with an outstanding principal amount of at least $50 million or $75 million, depending on the indenture.

We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance. The applicable rates for our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038 are 6.86%, 8.0% and 8.0%, respectively.

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

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

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

During 2013, we issued $2.3 billion in aggregate principal amount of senior notes at par. The offering included three series of notes: $500 million in aggregate principal amount of 3.25% Senior Notes due 2016; $700 million in aggregate principal amount of 5.375% Senior Notes due 2021; and $1.1 billion in aggregate principal amount of 5.75% Senior Notes due 2023. We used a portion of the net proceeds of $2.274 billion to repay outstanding indebtedness under our revolving credit facility and purchase certain senior notes. We purchased $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to tender offers during 2013. We recorded a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million of unamortized deferred charges. During 2013, we also redeemed $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 (the 2019 Notes) at par pursuant to notice of special early redemption. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount. As described in the following paragraph, our redemption of the 2019 Notes has been the subject of litigation. On July 15, 2013, we retired at maturity the remaining $247 million aggregate principal amount outstanding of our 7.625% Senior Notes due 2013.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York against The Bank of New York Mellon Trust Company, N.A., the indenture trustee for the 2019 Notes. The Company sought and ultimately obtained a judgment declaring that the notice it issued on March 15, 2013 to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) was timely and effective for that redemption pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes. In May 2013, as a result of that ruling, the 2019 Notes were redeemed at par. In November 2014, the U.S. Court of Appeals for the Second Circuit, on appeal by the indenture trustee, reversed the District Court's declaratory judgment and held that the notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose. The Court of Appeals remanded the case to the District Court for a determination whether the redemption notice triggered a redemption at the make-whole price specified in the indenture, instead of at par. The Company sought a rehearing by the Court of Appeals *en banc* in December 2014, and that petition was denied on February 6, 2015. On February 13, 2015, the indenture trustee moved the District Court for entry of a judgment requiring the Company to pay the make-whole price, as defined in the indenture, less the par amount paid in the 2013 redemption plus prejudgment interest from the redemption date. On March 20, 2015, the Company filed its opposition to the Trustee's motion and cross-moved for a judgment requiring the Company to pay restitution in an amount that would disgorge the benefit the Company achieved from refinancing the 2019 Notes in 2013 and that would return the parties to the economic positions they would have been in if the par redemption had never taken place. On July 10, 2015, the District Court granted the Trustee's motion and denied the Company's cross-motion and entered an amended judgment on July 17, 2015 awarding the Trustee $380 million plus prejudgment interest in the amount of $59 million. The Company filed a notice of appeal on July 27, 2015 and posted a supersedeas bond to stay execution of the judgment while appellate proceedings are pending.

Revolving Credit Facility

In September and December 2015, we amended our $4.0 billion senior revolving credit facility dated December 15, 2014 and maturing December 2019, which is used for general corporate purposes. Pursuant to the amended credit agreement, we are required to secure our obligations under the facility with liens on certain of our oil and natural gas properties, with such liens to be released upon the satisfaction of specific conditions. The amended credit facility provides that, while the obligations are required to be secured, (i) we have the right to incur junior lien indebtedness of up to $4.0 billion; (ii) our use of the facility will be subject to a borrowing base; (iii) the rate of interest on outstanding loans, as well as fees on undrawn commitments, will vary based on the percentage of the borrowing base used, rather than on our credit ratings; (iv) the total leverage ratio covenant will be suspended; and (v) the credit facility will be subject to a first lien secured leverage ratio and an interest rate coverage ratio (as described below). The permitted junior lien debt basket of $4.0 billion may be increased upon the satisfaction of certain conditions, including the following: (i) after giving effect to all debt secured by such junior liens and the uses of such debt in retirement of other indebtedness, our net annual cash interest expense would increase by no more than $75 million, and (ii) we have exchanged debt secured by such junior liens for more than $2.0 billion aggregate principal amount of outstanding senior notes with maturities or initial put dates in 2017 through 2019. The September amendment sets the borrowing base at $4.0 billion. The total commitments under the credit facility remain at $4.0 billion, subject to reduction in connection with issuances of junior lien indebtedness by us after April 15, 2016, the date of the first borrowing base redetermination. No adjustment to the total commitment has occurred or will occur for any junior lien indebtedness issuance that occurs before April 15, 2016. As of December 31, 2015, we had no outstanding borrowings under the facility and had used $16 million of the facility for various letters of credit.

While obligations under our credit facility are required to be secured, revolving loans under the amended credit facility will bear interest, at our election, at either (i) a fluctuating rate per annum equal to the highest of (a) the federal funds effective rate plus 0.5%, (b) the administrative agent's prime rate or (c) the London interbank offer rate (LIBOR) for a one-month interest period plus 1.0% (alternative base rate (ABR) loans), or (ii) a LIBOR rate (LIBOR loans), in each case plus a margin based on the percentage of the borrowing base used (currently 1.0% per annum for ABR loans and 2.0% per annum for LIBOR loans). The terms of the 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, together with a requirement that we maintain, as of the last day of each fiscal quarter, a net debt to capitalization ratio (as defined in the amended credit agreement) that does not exceed 65%. While it is required to be secured by a portion of our oil and natural gas properties, the amended credit facility requires us to maintain, as of the last day of each fiscal quarter (i) a first lien secured leverage ratio (as defined in the amended credit agreement) of 3.5 to 1.0 through 2017 and no more than 3.0 to 1.0 thereafter, and (ii) an interest rate coverage ratio (as defined in the amended credit agreement) of at least 1.1 to 1.0 through the first quarter of 2017, increasing to 1.25 to 1.0 by the end of 2017.

Our credit facility is fully and unconditionally guaranteed, on a joint and several basis, by certain of our material subsidiaries. The amended credit agreement includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to indebtedness in an aggregate principal amount of $125 million or more; bankruptcy; judgments involving liability of $125 million or more that are not paid; and ERISA events. Many events of default are subject to customary notice and cure periods.

Term Loan

In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion. The term loan provided that it could be voluntarily repaid before November 9, 2015 at par plus a specified premium and at any time thereafter at par. The maturity date of the term loan was December 2, 2017. In 2014, we used a portion of the net proceeds from our offering of $3.0 billion in aggregate principal amount of senior notes to repay the borrowings under, and terminate, the term loan. We recorded a loss of $90 million, consisting of $40 million in premiums, $30 million of unamortized discount and $20 million of unamortized deferred charges, in connection with the termination.

Spin-Off Debt Transactions

On June 30, 2014, we completed the spin-off of our oilfield services business, which we previously conducted through our indirect, wholly owned subsidiary Chesapeake Oilfield Operating, L.L.C. (COO), into the independent, publicly traded company Seventy Seven Energy Inc. (SSE). In 2014, COO or its subsidiaries completed the following debt transactions:

- Entered into a five-year senior secured revolving credit facility with total commitments of $275 million and incurred approximately $3 million in financing costs related to entering into the facility.
- Entered into a $400 million seven-year secured term loan and used the net proceeds of approximately $394 million and borrowings under the new revolving credit facility to repay and terminate COO's then-existing credit facility.
- Issued $500 million in aggregate principal amount of 6.5% Senior Notes due 2022 in a private placement and used the net proceeds of approximately $494 million to make a cash distribution of approximately $391 million to us, to repay a portion of outstanding indebtedness under the new revolving credit facility discussed above and for general corporate purposes.

All deferred charges and debt balances related to these transactions were removed from our consolidated balance sheet as of June 30, 2014. See Note 13 for further discussion of the spin-off.

Fair Value of Debt

We estimate the fair value of our exchange-traded debt using quoted market prices (Level 1). The fair value of all other debt, which would include borrowings under our revolving credit facility (which was undrawn as of December 31, 2015 and 2014), is estimated using our credit default swap rate (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	December 31, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$ 381	$ 366	$ 381	$ 396
Long-term debt (Level 1)	$ 10,347	$ 3,735	$ 11,144	$ 11,656

4. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

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

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

Redemption of 2019 Notes. See Note 3 for a description of pending litigation regarding our redemption in May 2013 of our 2019 Notes. As a result of the reversal of the trial court's decision in our declaratory judgment action against the indenture trustee, we accrued a loss contingency of $100 million for this matter in 2014, and we accrued an additional $339 million in 2015 as a result of the judgment on remand entered on July 17, 2015. The loss contingency associated with this matter is fully accrued as of December 31, 2015.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

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

Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order from the Texas Multidistrict Litigation Panel to transfer a substantial portion of these lawsuits filed since June 2014 to the 348th District Court of Tarrant County for pre-trial purposes. On February 12, 2016, Chesapeake filed a motion to change venue for several other lawsuits to Harris County, or alternatively, to Tarrant County. These lawsuits, which primarily relate to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. In addition to allegations of breach of contract, a number of these lawsuits allege fraud, conspiracy, joint venture and antitrust violations by Chesapeake. Chesapeake expects that additional lawsuits will be filed by new plaintiffs making similar allegations. The lawsuits seek direct damages in varying amounts, together with exemplary damages, attorneys' fees, costs and interest.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and permanent injunction from further violations of the UTPCPL. On February 8, 2016, the Office of Attorney General amended the complaint to, among other things, add an additional UTPCPL claim and antitrust claim alleging that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company's divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and one of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources. We have not accrued a loss contingency for any of the Pennsylvania and Ohio matters seeking class certification.

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.

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

Environmental Contingencies

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

Commitments

Operating Leases

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

	December 31, 2015
	($ in millions)
2016	$ 4
2017	2
2018	2
2019	1
Total	$ 9

Lease expense for the years ended December 31, 2015, 2014 and 2013 was $7 million, $33 million and $158 million, respectively. Lease expense decreased significantly in 2015 and 2014 compared to 2013 primarily due to the repurchase of all rigs and compressors previously sold under long-term sale-leaseback arrangements.

Gathering, Processing and Transportation Agreements

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

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, 2015
	($ in millions)
2016	$ 1,932
2017	1,944
2018	1,742
2019	1,443
2020	1,111
2021 – 2099	5,793
Total	$ 13,965

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 vary with the applicable agreement. One of these agreements in the Anadarko Basin in northwestern Oklahoma and the Texas panhandle contains cost-of-service based fees that are redetermined annually through 2019. The annual upward or downward fee adjustment for this contract is capped at 15% of the then-current fees at the time of redetermination. To the extent the actual rate of return on capital expended by the counterparty over the term of the agreement differs from the applicable rate of return, a payment is due to (from) the midstream service company.

Drilling Contracts

We have contracts with various drilling contractors to utilize drilling services with terms ranging from three months to three years at market-based pricing. These commitments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2015, the aggregate undiscounted minimum future payments under these drilling service commitments are detailed below.

	December 31, 2015
	($ in millions)
2016	$ 160
2017	114
2018	6
Total	$ 280

Pressure Pumping Contracts

In connection with the spin-off of our oilfield services business in June 2014, we entered into an agreement with a subsidiary of SSE for pressure pumping services. The services agreement requires us to utilize, at market-based pricing, the lesser of (i) seven, five and three pressure pumping crews in years one, two and three of the agreement, respectively, or (ii) 50% of the total number of all pressure pumping crews working for us in all of our operating regions during the respective year. We are also required to utilize SSE pressure pumping services for a minimum number of fracture stages as set forth in the agreement. We are entitled to terminate the agreement in certain situations, including if SSE fails to provide the overall quality of service provided by similar service providers. As of December 31, 2015, the aggregate undiscounted minimum future payments under this agreement are detailed below.

	December 31, 2015
	($ in millions)
2016	$ 122
2017	64
Total	$ 186

Drilling Commitments

We have committed to drill wells for the benefit of Chesapeake Granite Wash Trust. See *Noncontrolling Interests* in Note 8 for discussion of this commitment.

Oil, Natural Gas and NGL Purchase Commitments

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

Net Acreage Maintenance Commitments

Under the terms of our Barnett and Utica Shale joint venture agreements with Total S.A. (see *Joint Ventures* in Note 12), we are required to extend, renew or replace expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas as of future measurement dates. 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, which is included in impairments of fixed assets and other in our consolidated statement of operations.

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

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

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

5. Other Liabilities

Other current liabilities as of December 31, 2015 and 2014 are detailed below.

	December 31, 2015	December 31, 2014
	($ in millions)	
Revenues and royalties due others	$ 500	$ 1,176
Accrued drilling and production costs	212	385
Joint interest prepayments received	169	189
Accrued compensation and benefits	264	344
Other accrued taxes	21	55
Accrued dividends	—	101
Bank of New York Mellon legal accrual	439	100
Oklahoma royalty settlement	—	119
Minimum gathering volume commitment [(a)]	201	141
Other	413	451
Total other current liabilities	$ 2,219	$ 3,061

(a) Minimum gathering volume commitments are presented on a gross basis. We have recorded receivables from certain of our working interest partners for their proportionate share of the liabilities of $27 million and $21 million as of December 31, 2015 and 2014, respectively.

Other long-term liabilities as of December 31, 2015 and 2014 are detailed below.

	December 31, 2015	December 31, 2014
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$ 190	$ 220
CHK C-T ORRI conveyance obligation[(b)]	—	135
Financing obligations	29	30
Unrecognized tax benefits	64	45
Other	126	249
Total other long-term liabilities	$ 409	$ 679

(a) $21 million and $14 million of the total $211 million and $234 million obligations are recorded in other current liabilities as of December 31, 2015 and 2014, respectively. See *Noncontrolling Interests* in Note 8 for further discussion of the conveyance obligation.

(b) $23 million of the total $158 million obligation is recorded in other current liabilities as of December 31, 2014. In 2015, we sold the oil and natural gas properties held by CHK Cleveland Tonkawa, L.L.C. (CHK C-T) and eliminated our ORRI obligation attributable to CHK C-T. See *Noncontrolling Interests* in Note 8 for further discussion of the transaction.

6. Income Taxes

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

	Years Ended December 31,		
	2015	2014	2013
		($ in millions)	
Current			
Federal	$ —	$ —	$ —
State	(36)	47	22
Current Income Taxes	(36)	47	22
Deferred			
Federal	(4,385)	1,115	502
State	(42)	(18)	24
Deferred Income Taxes	(4,427)	1,097	526
Total	$ (4,463)	$ 1,144	$ 548

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,		
	2015	2014	2013
		($ in millions)	
Income tax expense (benefit) at the federal statutory rate (35%)	$ (6,684)	$ 1,120	$ 505
State income taxes (net of federal income tax benefit)	(406)	68	88
Remeasurement of state deferred tax liabilities	—	(114)	(38)
Change in valuation allowance	2,727	74	(12)
Other	(100)	(4)	5
Total	$ (4,463)	$ 1,144	$ 548

We reassessed the realizability of our deferred tax assets given the decline in commodity prices and recorded a $2.727 billion tax expense for the year ended December 31, 2015 for the increase in our valuation allowance.

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

	Years Ended December 31,	
	2015	2014
	($ in millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ —	$ (3,829)
Volumetric production payments	(802)	(1,023)
Carrying value of debt	—	(443)
Derivative instruments	(294)	(428)
Other	(74)	(114)
Deferred tax liabilities	(1,170)	(5,837)
Deferred tax assets:		
Property, plant and equipment	1,140	—
Net operating loss carryforwards (carrybacks)	1,556	945
Carrying value of debt	535	—
Asset retirement obligations	174	165
Investments	132	84
Accrued liabilities	332	239
Other	250	234
Deferred tax assets	4,119	1,667
Valuation allowance	(2,949)	(222)
Net deferred tax assets	1,170	1,445
Net deferred tax assets (liabilities)	$ —	$ (4,392)
Reflected in accompanying balance sheets as:		
Non-current deferred income tax liability	$ —	$ (4,392)
Total	$ —	$ (4,392)

In connection with the exchange of our 8.00% Senior Secured Second Lien Notes due 2022, for Existing Notes, we recognized approximately $2.8 billion of cancellation of indebtedness income for tax purposes. The income from the cancellation of indebtedness is included in the deferred tax asset on property, plant and equipment.

As of December 31, 2015, Chesapeake had federal income tax NOL carryforwards of approximately $3.2 billion and state NOL carryforwards of approximately $9.5 billion which excludes the NOL carryforwards related to unrecognized tax benefits and stock compensation windfalls that have not been recognized under U.S. GAAP. The associated deferred tax assets related to these NOL carryforwards were $1.107 billion and $449 million. Additionally, we had $31 million of alternative minimum tax (AMT) NOL carryforwards, net of unrecognized tax benefits, available as a deduction against future AMT income. The NOL carryforwards expire from 2031 through 2035. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. As of December 31, 2015 and 2014, we had deferred tax assets of $4.119 billion and $1.667 billion, respectively, upon which we had a valuation allowance of $2.949 billion and $222 million, respectively. The net change in the valuation allowance of $2.727 billion for both federal and state deferred tax assets is reflected as a component of income tax expense.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the cumulative loss incurred over the three-year period ending December 31, 2015. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

Deferred tax assets relating to tax benefits of employee share-based compensation have been reduced for stock options exercised and restricted stock that vested in periods in which Chesapeake was in a net operating loss (NOL) position. Some exercises and vestings result in tax deductions in excess of previously recorded benefits based on the stock option or restricted stock value at the time of grant (windfalls). Although these additional tax benefits or windfalls are reflected in NOL carryforwards in the tax return, the additional tax benefit associated with the windfalls is not recognized until the deduction reduces taxes payable pursuant to accounting for stock compensation under U.S. GAAP. Accordingly, since the tax benefit does not reduce Chesapeake's current taxes payable due to NOL carryforwards, these windfall tax benefits are not reflected in Chesapeake's NOLs in deferred tax assets. Windfalls included in NOL carryforwards but not reflected in deferred tax assets as of December 31, 2015 totaled $19 million. Any shortfalls resulting from tax deductions that were less than the previously recorded benefits were recorded as reductions to additional paid-in capital.

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of these carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

As of December 31, 2015, we do not believe that an ownership change has occurred that would limit the carryforwards. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. As of December 31, 2015 and 2014, the amount of unrecognized tax benefits related to NOL carryforwards and state tax liabilities associated with uncertain tax positions was $280 million and $303 million, respectively. Of the 2015 amount, $44 million is related to state tax liabilities while the remainder is related to NOL carryforwards. Of the 2014 amount, $23 million and $17 million are related to AMT and state tax liabilities, respectively, while the remainder is related to NOL carryforwards. The uncertain tax positions identified would not have a material effect on the effective tax rate. No material changes to the current uncertain tax positions are expected within the next 12 months. As of December 31, 2015 and 2014, we had accrued liabilities of $20 million and $5 million, respectively, for interest related to these uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

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

	2015	2014	2013
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 303	$ 644	$ 599
Additions based on tax positions related to the current year	27	13	15
Additions to tax positions of prior years	—	—	30
Reductions to tax positions of prior years	(50)	(354)	—
Unrecognized tax benefits at end of period	$ 280	$ 303	$ 644

Chesapeake's federal and state income tax returns are routinely audited by federal and state fiscal authorities. The Internal Revenue Service (IRS) is currently auditing our federal income tax returns for 2010 through 2013. The 2010 through 2015 years and the 2007 through 2015 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. During 2015, 2014 and 2013, we had the following transactions with our equity method investees:

	Years Ended December 31,		
	2015	2014	2013
		($ in millions)	
Sales[(a)]	$ —	$ —	$ 666
Services[(b)]	$ 65	$ 220	$ 397

(a) In 2013, Chesapeake sold produced gas to our 30%-owned investee, Twin Eagle Resource Management LLC (Twin Eagle). We sold our investment in Twin Eagle in 2014.

(b) Hydraulic fracturing and other services are provided to us by FTS International, Inc. in the ordinary course of business. As well operators, we are reimbursed by other working interest owners through the joint interest billing process for their proportionate share of these costs.

8. Equity

Common Stock

The following is a summary of the changes in our common shares issued for the years ended December 31, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
		(in thousands)	
Shares issued as of January 1	664,944	666,192	666,468
Restricted stock issuances (net of forfeitures and cancellations)[(a)]	(163)	(2,529)	(599)
Stock option exercises	15	1,281	323
Shares issued as of December 31	664,796	664,944	666,192

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

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2015:

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	39.6526	$ 25.2190	May 17, 2015	$ 32.7847
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	38.3186	$ 26.0970	May 17, 2015	$ 33.9261
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.

The following reflects the shares outstanding of our preferred stock for the years ended December 31, 2015, 2014 and 2013:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2015, 2014 and 2013 and shares outstanding as of December 31, 2015, 2014 and 2013	1,497	1,100	2,559	2,096

Dividends

Dividends declared on our common stock and 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, dividend declarations are accounted for as a reduction to paid-in capital.

In July 2015, our Board of Directors determined to eliminate quarterly cash dividends on our common stock. In January 2016, we announced that we were suspending payment of dividends on each series of our outstanding convertible preferred stock. Suspension of the dividends did not constitute an event of default under our revolving credit facility or bond indentures. 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.

Accumulated Other Comprehensive Income (Loss)

For the years ended December 31, 2015 and 2014, changes in accumulated other comprehensive income (loss) by component, net of tax, are detailed below.

	Cash Flow Hedges	Investments	Net Change
		($ in millions)	
Balance, December 31, 2014	$ (143)	$ —	$ (143)
Other comprehensive income before reclassifications	20	—	20
Amounts reclassified from accumulated other comprehensive income	24	—	24
Net other comprehensive income	44	—	44
Balance, December 31, 2015	$ (99)	$ —	$ (99)
Balance, December 31, 2013	$ (167)	$ 5	$ (162)
Other comprehensive income before reclassifications	1	—	1
Amounts reclassified from accumulated other comprehensive income	23	(5)	18
Net other comprehensive income	24	(5)	19
Balance, December 31, 2014	$ (143)	$ —	$ (143)

For the years ended December 31, 2015 and 2014, amounts reclassified from accumulated other comprehensive income (loss), net of tax, into the consolidated statements of operations are detailed below.

Details About Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income is Presented	Amounts Reclassified
		($ in millions)
Year Ended December 31, 2015		
Net losses on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$ 23
Foreign currency derivative	Gain (loss) on purchases or exchanges of debt	1
Total reclassifications for the period, net of tax		$ 24
Year Ended December 31, 2014		
Net losses on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$ 23
Investments:		
Sale of investment	Net gain on sale of investment	(5)
Total reclassifications for the period, net of tax		$ 18

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK C-T in March 2012 to continue development of a portion of our oil and natural gas assets in our Cleveland and Tonkawa plays. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and the existing wells within an area of mutual interest in the plays between the top of the Tonkawa and the top of the Big Lime formations covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 future net wells to be drilled on the contributed play leasehold. We initially committed to drill and complete, for the benefit of CHK C-T in the area of mutual interest, a minimum cumulative total of 300 net wells. We ultimately drilled and completed 190 net wells, and the drilling commitment was suspended in January 2015.

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

As of December 31, 2014, $1.015 billion of noncontrolling interests on our consolidated balance sheets was attributable to CHK C-T. For 2015, 2014 and 2013, income of $50 million, $75 million and $75 million, respectively, was attributable to the noncontrolling interests of CHK C-T.

Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale oil and natural gas assets. In exchange for all of the common shares of CHK Utica, we contributed to CHK Utica approximately 700,000 net acres of leasehold and the existing wells within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% ORRI in 1,500 net wells to be drilled on certain of our Utica Shale leasehold.

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

The CHK Utica investors' right to receive, proportionately, a 3% ORRI in the first 1,500 net wells drilled on our Utica Shale leasehold is subject to an increase to 4% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs through 2023. However, in no event are we required to deliver to investors more than a total ORRI of 3% in 1,500 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 150-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of the remaining ORRIs. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of the remaining ORRIs once we have drilled a minimum of 1,300 net wells. As of December 31, 2015, we had drilled 499 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our oil and natural gas properties. Because we did not meet our ORRI commitment in 2012, the ORRI increased to 4% for wells earned in 2013, and the ultimate number of wells in which we must assign an interest was reduced accordingly. We met our ORRI conveyance commitments as of December 31, 2013, 2014 and 2015.

In 2014 and 2013, income of approximately $43 million and $79 million, respectively, was attributable to the noncontrolling interests of CHK Utica.

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

In connection with the Trust's initial public offering, we conveyed royalty interests to the Trust that entitle the Trust to receive (i) 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) that we receive from the production of hydrocarbons from 69 then-producing wells, and (ii) 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) in 118 development wells that have been or will be drilled on approximately 45,400 gross acres (29,000 net acres) in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma. Pursuant to the terms of a development agreement with the Trust, we are obligated to drill and complete, or cause to be drilled and completed, the development wells at our own expense prior to June 30, 2016, and the Trust is not responsible for any costs related to the drilling and completion of the development wells or any other operating or capital costs of the Trust properties. In addition, we granted to the Trust a lien on our remaining interests in the undeveloped properties that are subject to the development agreement in order to secure our drilling obligation to the Trust, although the maximum amount recoverable by the Trust under the lien was limited to $263 million initially and is proportionately reduced as we fulfill our drilling obligation over time. As of December 31, 2015, we had drilled and completed or caused to be drilled and completed approximately 106 development wells, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $27 million.

The subordinated units we hold in the Trust are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is not less than the applicable subordination threshold for the quarter. If there is not sufficient cash to fund a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units is reduced or eliminated for the quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. The distribution made with respect to the subordinated units to Chesapeake was either reduced or eliminated for each of the most recent 14 quarters. In exchange for agreeing to subordinate a portion of our Trust units, and in order to provide additional financial incentive to us to satisfy our drilling obligation and perform operations on the underlying properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on the Trust units in any quarter exceeds the applicable incentive threshold for the quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold is to be paid to Trust unitholders, including Chesapeake, on a pro rata basis. Through December 31, 2015, no incentive distributions had been made. At the end of the fourth full calendar quarter following our satisfaction of our drilling obligation with respect to the development wells, the subordinated units will automatically convert into common units on a one-for-one basis and our right to receive incentive distributions will terminate. After this time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share in the Trust's distributions on a pro rata basis.

For the years ended December 31, 2015, 2014 and 2013, the Trust declared and paid the following distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
June 2015 – August 2015	November 30, 2015	$ 0.3232	$ —
March 2015 – May 2015	August 31, 2015	$ 0.3579	$ —
December 2014 – February 2015	June 1, 2015	$ 0.3899	$ —
September 2014 – November 2014	March 2, 2015	$ 0.4496	$ —
June 2014 – August 2014	December 1, 2014	$ 0.5079	$ —
March 2014 – May 2014	August 29, 2014	$ 0.5796	$ —
December 2013 – February 2014	May 30, 2014	$ 0.6454	$ —
September 2013 – November 2013	March 3, 2014	$ 0.6624	$ —
June 2013 – August 2013	November 29, 2013	$ 0.6671	$ —
March 2013 – May 2013	August 29, 2013	$ 0.6900	$ 0.1432
December 2012 – February 2013	May 31, 2013	$ 0.6900	$ 0.3010
September 2012 – November 2012	March 1, 2013	$ 0.6700	$ 0.3772

We have determined that the Trust is a variable interest entity (VIE) and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our consolidated financial statements. As of December 31, 2015 and 2014, approximately $259 million and $287 million, respectively, of noncontrolling interests on our consolidated balance sheets were attributable to the Trust. In 2015 we had net income of a nominal amount and in 2014 and 2013 we had net income of $24 million and $20 million, respectively, attributable to the Trust's noncontrolling interests in our consolidated statements of operations as income. See Note 15 for further discussion of VIEs.

9. Share-Based Compensation

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

Share-Based Compensation Plans

2014 Long Term Incentive Plan. Our 2014 Long Term Incentive Plan (2014 LTIP), which is administered by the Compensation Committee of our Board of Directors, became effective on June 13, 2014 after it was approved by shareholders at our 2014 Annual Meeting. The 2014 LTIP replaced our Amended and Restated Long Term Incentive Plan (2005 LTIP) which was adopted in 2005. The 2014 LTIP provides for up to 36,600,000 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; and (iii) 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. In 2015, we issued 225,630 and 5,440,420 shares of restricted stock, net of forfeitures, to non-employee directors and employees, respectively, under the 2014 LTIP. In 2014, we issued 50,771 and 272,289 shares of restricted stock net of forfeitures, to non-employee directors and employees, respectively, under the 2014 LTIP. Additionally in 2015, we issued options to purchase 1,208,185 shares of common stock to employees under the 2014 LTIP. As of December 31, 2015, 35,350,862 shares of common stock remained issuable under the 2014 LTIP.

2003 Stock Award Plan for Non-Employee Directors. Under Chesapeake's 2003 Stock Award Plan for Non-Employee Directors (2003 Non-Employee Director Plan), a maximum of 10,000 shares of Chesapeake's common stock is awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares issued may not exceed 250,000 shares. The plan was approved by our shareholders. We issued 10,000, 10,000 and 20,000 shares of common stock to newly appointed non-employee directors under the 2003 Non-Employee Director Plan in 2015, 2014 and 2013, respectively. In November 2015, our Board of Directors terminated the 2003 Non-Employee Director Plan.

Equity-Classified Awards

Restricted Stock. We grant restricted stock units to employees and non-employee directors. Prior to 2014, we also granted restricted stock awards as equity compensation. We refer to both types of awards as restricted stock. Restricted stock vests over a minimum of three years and the holder receives dividends, if paid, on unvested shares. A summary of the changes in unvested restricted stock during 2015, 2014 and 2013 is presented below.

	Shares of Unvested Restricted Stock	Weighted Average Grant Date Fair Value
	(in thousands)	
Unvested restricted stock as of January 1, 2015	10,091	$ 21.20
Granted	7,095	$ 13.90
Vested	(4,157)	$ 21.70
Forfeited	(2,574)	$ 16.98
Unvested restricted stock as of December 31, 2015	10,455	$ 17.31
Unvested restricted stock as of January 1, 2014	13,400	$ 23.38
Granted	5,049	$ 25.92
Vested	(4,803)	$ 27.17
Forfeited	(3,555)	$ 28.09
Unvested restricted stock as of December 31, 2014	10,091	$ 21.20
Unvested restricted stock as of January 1, 2013	18,899	$ 23.72
Granted	9,189	$ 19.68
Vested	(12,897)	$ 21.32
Forfeited	(1,791)	$ 22.86
Unvested restricted stock as of December 31, 2013	13,400	$ 23.38

The aggregate intrinsic value of restricted stock that vested during 2015 was approximately $59 million based on the stock price at the time of vesting.

As of December 31, 2015, there was approximately $109 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 1.85 years.

The vesting of certain restricted stock grants may result in state and federal income tax benefits, or reductions in these benefits, related to the difference between the market price of the Company's common stock at the date of vesting and the date of grant. During 2015 and 2013, we recognized reductions in tax benefits related to restricted stock of $12 million and $14 million, respectively. During 2014, we recognized an excess tax benefit related to restricted stock of $12 million. Each adjustment was recorded to additional paid-in capital and deferred income taxes.

Stock Options. In 2015, 2014 and 2013, we granted members of senior management stock options that vest ratably over a three-year period. In January 2013, we also granted retention awards of stock options to certain officers that vest one-third on each of the third, fourth and fifth anniversaries of the grant date. Each stock option award has an exercise price equal to the closing price of the Company's common stock on the grant date. Outstanding options expire seven to ten years from the date of grant.

We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The expected life of an option is determined using the simplified method, as there is no adequate historical exercise behavior available. Volatility assumptions are estimated based on an average of historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account the Company's dividend policy, over the expected life of the option. The Company used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in 2015:

Expected option life – years	4.5
Volatility	39.91%
Risk-free interest rate	1.33%
Dividend yield	1.91%

The following table provides information related to stock option activity for 2015, 2014 and 2013:

	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 at 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 at December 31, 2015	5,377	$ 19.37	5.80	$ —
Exercisable at December 31, 2015	2,045	$ 19.61	5.07	$ —
Outstanding at January 1, 2014	5,268	$ 19.28	6.66	$ 41
Granted	994	$ 24.43		
Exercised	(1,322)	$ 18.71		$ 11
Expired	(28)	$ 18.97		
Forfeited	(313)	$ 21.05		
Outstanding at December 31, 2014	4,599	$ 19.55	7.03	$ 5
Exercisable at December 31, 2014	1,304	$ 18.71	5.70	$ 1
Outstanding at January 1, 2013	481	$ 12.69	0.96	$ 2
Granted	5,264	$ 19.32		
Exercised	(346)	$ 10.82		$ 3
Expired	(131)	$ 19.31		
Outstanding at December 31, 2013	5,268	$ 19.28	6.66	$ 41
Exercisable at December 31, 2013	1,552	$ 18.82	1.97	$ 13

(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, 2015, there was $8 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 1.56 years.

The vesting of certain stock option grants may result in state and federal income tax benefits, or reductions in these benefits, related to the difference between the market price of the common stock at the date of vesting and the date of grant. During 2015, we did not recognize any reductions or excess in tax benefits related to stock options. During 2014 and 2013, we recognized excess tax benefits related to stock options of $3 million and $1 million, respectively. Each adjustment was recorded to additional paid-in capital and deferred income taxes.

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, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
General and administrative expenses	$ 43	$ 46	$ 60
Oil and natural gas properties	23	29	52
Oil, natural gas and NGL production expenses	18	18	21
Marketing, gathering and compression expenses	5	6	7
Oilfield services expenses	—	5	10
Total	$ 89	$ 104	$ 150

Liability-Classified Awards

Performance Share Units. In 2013, 2014 and 2015, we 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 and proved reserve growth.

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%. The payout percentage for these PSUs is capped at 100% if the Company's absolute TSR is less than zero. For PSUs granted in 2014, the TSR component can range from 0% to 200%, with no operational components. For PSUs granted in 2013, the TSR component can range from 0% to 125% of base salary, and each of the two operational components can range from 0% to 62.5%; however, the maximum total payout is capped at 200%. Compensation expense associated with PSU grants is recognized over the service period based on the graded-vesting method. The number of units settled is dependent upon the Company's estimates of the underlying performance measures. The Company utilized the Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs:

Volatility	55.76%
Risk-free interest rate	1.06%
Dividend yield for value of awards	—%

The following table presents a summary of our 2015, 2014 and 2013 PSU awards:

	Units	Fair Value as of Grant Date	Fair Value[a]	Liability for Vested Amount[a]
			($ in millions)	
2015 Awards:				
Payable 2018	696,683	$ 13	$ 2	$ 1
2014 Awards:				
Payable 2017	609,637	$ 16	$ —	$ —
2013 Awards:				
Payable 2016	1,701,941	$ 35	$ 4	$ 4

(a) As of December 31, 2015.

PSU Compensation. We recognized the following compensation costs (credits) related to PSUs for the years ended December 31, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
		($ in millions)	
General and administrative expenses	$ (19)	$ (4)	$ 34
Restructuring and other termination costs	(19)	(19)	29
Marketing, gathering and compression	(1)	—	2
Oil and natural gas properties	(2)	3	9
Oil, natural gas and NGL production expenses	—	—	2
Oilfield services expenses	—	—	1
Total	$ (41)	$ (20)	$ 77

Effect of the Spin-off on Share-Based Compensation

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

10. Employee Benefit Plans

Our qualified 401(k) profit sharing plan (401(k) Plan) is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the IRS. Through December 31, 2014, Chesapeake matched employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee's base salary and performance bonus) with Chesapeake common stock purchased in the open market. Beginning January 1, 2015, Chesapeake matched employee contributions in cash. The Company contributed $52 million, $61 million and $81 million to the 401(k) Plan in 2015, 2014 and 2013, respectively.

Chesapeake also maintains a nonqualified deferred compensation plan (DC Plan). To be eligible to participate in the DC Plan, an active employee must have a base salary of at least $150,000, have a hire date on or before December 1, immediately preceding the year in which the employee is able to participate, or be designated as eligible to participate. Only the top 10% of Company wage earners are eligible to participate. Additionally, the employee had to have made the maximum contribution allowable under the 401(k) Plan. Chesapeake matches 100% of employee contributions up to 15% of base salary and performance bonus in the aggregate for the DC Plan with Chesapeake common stock, and an employee who is at least age 55 may elect for the matching contributions to be made in any one of the DC Plan’s investment options. The maximum compensation that can be deferred by employees under all Company deferred compensation plans, including the Chesapeake 401(k) Plan, is a total of 75% of base salary and 100% of performance bonus. The Company contributed $11 million, $7 million and $14 million to the DC Plan during 2015, 2014 and 2013, respectively, to fund the match. Beginning in 2016, the DC Plan will no longer be 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% will continue in 2016 and will be based on a five-year vesting schedule based on years of service. Any participant who is active on December 31 of the plan year will receive the deferred compensation company match which will be awarded on an annual basis.

Any assets placed in trust by Chesapeake to fund future obligations of the Company's nonqualified deferred compensation plans are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company as to their deferred compensation in the plans. Chesapeake maintains no post-employment benefit plans except those sponsored by its wholly owned subsidiary Chesapeake Appalachia, L.L.C. Participation in these plans is limited to existing employees who are union members and former employees who were union members. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2015, the Company had accrued approximately $3 million in accumulated post-employment benefit liability.

11. Derivative and Hedging Activities

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

Oil and Natural Gas Derivatives

As of December 31, 2015 and 2014, our oil and natural gas derivative instruments consisted of the following types of instruments:

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

The estimated fair values of our oil and natural gas derivative instrument assets (liabilities) as of December 31, 2015 and 2014 are provided below.

	December 31, 2015		December 31, 2014	
	Volume	Fair Value	Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	13.5	$ 144	12.5	$ 471
Three-way collars	—	—	4.4	40
Call options	19.2	(7)	35.8	(89)
Basis protection swaps	—	—	—	—
Total oil	32.7	137	52.7	422
Natural gas (tbtu):				
Fixed-price swaps	500	$ 229	275	$ 281
Three-way collars	—	—	207	165
Call options	295	(99)	193	(170)
Basis protection swaps	57	—	60	23
Total natural gas	852	130	735	299
Total estimated fair value		$ 267		$ 721

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

Interest Rate Derivatives

As of December 31, 2015, there were no interest rate derivatives outstanding. As of December 31, 2014, our interest rate derivative instruments consisted of swaps. We enter into 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. We enter into 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.

The notional amount of our interest rate derivatives associated with our long-term debt as of December 31, 2014 was $850 million. The estimated fair value of our interest rate derivative liabilities as of December 31, 2014 was $17 million.

We have terminated certain fair value hedges related to certain of our senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next six years, we will recognize $7 million in net gains related to these transactions.

Foreign Currency Derivatives

We are party to cross currency swaps to mitigate our exposure to foreign currency exchange rate fluctuations. In December 2015, we exchanged in privately negotiated transactions and subsequently retired €42 million in aggregate principal amount of these senior notes, and we simultaneously unwound the cross currency swaps for the same principal amount at a cost of $8 million. As a result, we realized a loss of $8 million which was included in losses on purchases or exchanges of debt. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €9 million and we pay the counterparties $15 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €302 million and we will pay the counterparties $403 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. The swaps are designated as cash flow hedges and, because they are entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value do not impact earnings. The fair values of the cross currency swaps are recorded on the consolidated balance sheets as liabilities of $52 million and $53 million as of December 31, 2015 and 2014, respectively. The euro-denominated debt in long-term debt has been adjusted to $329 million as of December 31, 2015, using an exchange rate of $1.0862 to €1.00.

Supply Contract Derivatives

From time to time and in the normal course of business, our marketing subsidiary enters into supply contracts under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas, thereby creating an embedded derivative requiring bifurcation. In one of these supply contracts, we are committed to supply a minimum of 90 bbtu per day of natural gas through March 2025. In 2015, we recorded revenues of approximately $96 million for settlements of this embedded derivative. The bifurcated derivative was measured at fair value resulting in an unrealized gain of $297 million in 2015. Both settlements and mark-to-market gains (losses) are included in marketing, gathering and compression revenues in our consolidated statements of operations.

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, 2015 and 2014 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in Consolidated Balance Sheet	Net Fair Value Presented in Consolidated Balance Sheet
		($ in millions)	
As of December 31, 2015			
Commodity Contracts:			
Short-term derivative asset	$ 381	$ (66)	$ 315
Long-term derivative asset	—	—	—
Short-term derivative liability	(106)	66	(40)
Long-term derivative liability	(8)	—	(8)
Total commodity contracts	267	—	267
Foreign Currency Contracts:[(a)]			
Long-term derivative liability	(52)	—	(52)
Total foreign currency contracts	(52)	—	(52)
Supply Contracts:			
Short-term derivative asset	51	—	51
Long-term derivative asset	246	—	246
Total supply contracts	297	—	297
Total derivatives	$ 512	$ —	$ 512

Balance Sheet Classification	Gross Fair Value	Amounts Netted in Consolidated Balance Sheet	Net Fair Value Presented in Consolidated Balance Sheet
As of December 31, 2014			
Commodity Contracts:			
Short-term derivative asset	$ 973	$ (95)	$ 878
Long-term derivative asset	16	(10)	6
Short-term derivative liability	(105)	95	(10)
Long-term derivative liability	(163)	10	(153)
Total commodity contracts	721	—	721
Interest Rate Contracts:			
Short-term derivative liability	(5)	—	(5)
Long-term derivative liability	(12)	—	(12)
Total interest rate contracts	(17)	—	(17)
Foreign Currency Contracts:[a]			
Long-term derivative liability	(53)	—	(53)
Total foreign currency contracts	(53)	—	(53)
Supply Contracts:			
Short-term derivative asset	1	—	1
Long-term derivative asset	—	—	—
Total supply contracts	1	—	1
Total derivatives	$ 652	$ —	$ 652

(a) Designated as cash flow hedging instruments.

As of December 31, 2015 and 2014, 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, 2015, 2014 and 2013 are presented below.

	Years Ended December 31, 2015	2014	2013
		($ in millions)	
Oil, natural gas and NGL revenues	$ 4,767	$ 9,336	$ 8,497
Gains (losses) on undesignated oil and natural gas derivatives	661	1,055	443
Losses on terminated cash flow hedges	(37)	(37)	(314)
Total oil, natural gas and NGL revenues	$ 5,391	$ 10,354	$ 8,626

The components of marketing, gathering and compression revenues for the years ended December 31, 2015, 2014 and 2013 are presented below.

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
Marketing, gathering and compression revenues	$ 7,077	$ 12,224	$ 9,559
Gains on undesignated supply contract derivatives	296	1	—
Total marketing, gathering and compression revenues	$ 7,373	$ 12,225	$ 9,559

The components of interest expense for the years ended December 31, 2015, 2014 and 2013 are presented below.

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
Interest expense on senior notes	$ 682	$ 704	$ 740
Interest expense on term loan	—	36	116
Amortization of loan discount, issuance costs and other	59	42	91
Interest expense on credit facilities	12	28	38
Gains on terminated fair value hedges	(3)	(3)	(5)
(Gains) losses on undesignated interest rate derivatives	(9)	(81)	63
Capitalized interest	(424)	(637)	(816)
Total interest expense	$ 317	$ 89	$ 227

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,					
	2015		2014		2013	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)					
Balance, beginning of period	$ (231)	$ (143)	$ (269)	$ (167)	$ (304)	$ (189)
Net change in fair value	32	20	1	1	3	2
Losses reclassified to income	39	24	37	23	32	20
Balance, end of period	$ (160)	$ (99)	$ (231)	$ (143)	$ (269)	$ (167)

Approximately $113 million of the $99 million of accumulated other comprehensive loss as of December 31, 2015 represented the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. Deferred gain or loss amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of December 31, 2015, we expect to transfer approximately $21 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

Over-the-counter traded derivative instruments and our supply contracts expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2015, our oil, natural gas, foreign currency and supply contract derivative instruments were spread among 16 counterparties.

Hedging Arrangements

As of December 31, 2015, our secured commodity hedging facility with three counterparties provided approximately 94 mmboe of hedging capacity for oil, natural gas and NGL price derivatives and 94 mmboe for basis derivatives with an aggregate mark-to-market capacity of $1.5 billion. The facility, which was terminated in February 2016, was secured by proved reserves, the value of which covered the fair value of the transactions outstanding under the facility by at least 1.65 times at semi-annual collateral redetermination dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our revolving credit facility and indentures. The counterparties' obligations under the facility were required to be secured by cash or short-term U.S. treasury instruments to the extent that any mark-to-market amounts owed to us exceed defined thresholds. As of December 31, 2015, we had hedged under the facility 1.2 mmboe of our future production with price derivatives.

In 2015, we also began entering into bilateral hedging agreements with the intention of replacing and terminating the respective counterparties' positions in the secured hedging facility. We also entered into bilateral arrangements that reduced the aggregate mark-to-market capacity under the secured hedging facility from $16.5 billion to $1.5 billion. The counterparties' and our obligations under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. Our obligations under other bilateral hedging agreements are secured by the same collateral securing our revolving credit facility. As of December 31, 2015, we had hedged under bilateral agreements 164.0 mmboe of our future production with price derivatives and 9.5 mmboe with basis derivatives.

Fair Value

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

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2015 and 2014:

	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, 2015				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 372	$ 9	$ 381
Commodity liabilities	—	(14)	(100)	(114)
Interest rate liabilities	—	—	—	—
Foreign currency liabilities	—	(52)	—	(52)
Supply contract assets	—	—	297	297
Total derivatives	$ —	$ 306	$ 206	$ 512
As of December 31, 2014				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 784	$ 205	$ 989
Commodity liabilities	—	(9)	(259)	(268)
Interest rate liabilities	—	(17)	—	(17)
Foreign currency liabilities	—	(53)	—	(53)
Supply contract assets	—	—	1	1
Total derivatives	$ —	$ 705	$ (53)	$ 652

A summary of the changes in the fair values of Chesapeake's financial assets (liabilities) classified as Level 3 during 2015 and 2014 is presented below.

	Commodity Derivatives	Supply Contracts
	($ in millions)	
Beginning balance as of January 1, 2015	$ (54)	$ 1
Total gains (losses) (unrealized):		
Included in earnings[(a)]	100	316
Total purchases, issuances, sales and settlements:		
Settlements	(137)	(20)
Ending balance as of December 31, 2015	$ (91)	$ 297
Beginning balance as of January 1, 2014	$ (478)	$ —
Total gains (losses) (unrealized):		
Included in earnings[(a)]	292	1
Total purchases, issuances, sales and settlements:		
Settlements	136	—
Transfers[(b)]	(4)	—
Ending balance as of December 31, 2014	$ (54)	$ 1

(a)

	Oil, Natural Gas and NGL Sales		Marketing, Gathering and Compression Revenue	
	2015	2014	2015	2014
	($ in millions)			
Total gains (losses) included in earnings for the period	$ 100	$ 292	$ 296	$ 1
Change in unrealized gains (losses) related to assets still held at reporting date	$ 43	$ 262	$ 296	$ —

(b) The values related to basis swaps were transferred from Level 3 to Level 2 as a result of our ability to begin using data readily available in the public market to corroborate our estimated fair values.

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 oil and natural gas, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts. 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, 2015:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2015
				($ in millions)
Oil trades[(a)]	Oil price volatility curves	26.87% – 43.08%	35.52%	$ (7)
Supply contracts[(b)]	Oil price volatility curves	20.01% – 43.81%	24.07%	$ 297
Natural gas trades[(a)]	Natural gas price volatility curves	19.84% – 73.05%	34.29%	$ (84)

(a) Fair value is based on an estimate derived from option models.

(b) Fair value is based on an estimate derived from industry standard methodologies which consider historical relationships among various commodities, modeled market prices, time value and volatility factors.

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.

2015 Transactions

CHK C-T sold all of its oil and natural gas properties to FourPoint and 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 for approximately $90 million.

Excluding proceeds received from selling additional interests in our joint venture leasehold described under *Joint Ventures* below, in 2015 we received proceeds related to divestitures of other noncore oil and natural gas properties of approximately $66 million.

2014 Transactions

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

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

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

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

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

Excluding proceeds received from selling additional interests in our joint venture leasehold described under *Joint Ventures* below, in 2014 we received proceeds related to divestitures of other noncore oil and natural gas properties of approximately $379 million.

2013 Transactions

We sold a wholly owned subsidiary, MKR Holdings, L.L.C. (MKR), to Chief Oil and Gas and two of its working interest partners, Enerplus Corporation and Tug Hill Operating. Net proceeds from the transaction were approximately $490 million. MKR held producing wells and undeveloped acreage in the Marcellus Shale.

We sold assets in the Haynesville Shale to EXCO Operating Company, LP (EXCO) for net proceeds of approximately $257 million. Subsequent to closing, we received approximately $47 million of additional net proceeds for post-closing adjustments. The assets sold included our operated and non-operated interests in approximately 9,600 net acres in DeSoto and Caddo parishes, Louisiana.

We sold noncore leasehold interests and producing properties in the northern Eagle Ford Shale to EXCO for net proceeds of approximately $617 million. Subsequent to closing, we received approximately $57 million and $32 million in 2014 and 2013, respectively, of additional net proceeds and for post-closing adjustments. The assets sold included approximately 55,000 net acres in Zavala, Dimmit, La Salle and Frio counties, Texas.

Joint Ventures

Between July 2008 and June 2013, we entered into eight significant joint ventures with other leading energy companies, including Sinopec International Petroleum Exploration and Production (Sinopec), Total S.A. (Total), CNOOC Limited, Statoil, BP America and Freeport-McMoRan Inc. (formerly known as Plains Exploration & Production Company), pursuant to which we sold portions ranging from 20% to 50% of certain leasehold, producing properties and other assets located in eight different resource plays. In return, we received aggregate cash proceeds of $8.0 billion and commitments by our joint venture partners to pay, in the aggregate, our share of future drilling and completion costs of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all drilling, completion and operations, the majority of leasing and, in certain transactions, marketing activities for the project. Each joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner and, if applicable, pays a specified percentage of our drilling and completion costs in designated wells. As of December 31, 2015, we had utilized all drilling carries from our joint venture partners. In 2015, 2014 and 2013, our drilling and completion costs included the benefit of approximately $51 million, $679 million and $884 million, respectively, in drilling and completion carries paid by our joint venture partners.

In 2013, we entered into a joint venture with Sinopec in which Sinopec purchased a 50% undivided interest in approximately 850,000 acres in the Mississippian Lime play in northern Oklahoma for $1.11 billion. There was no drilling and completion carry associated with this transaction.

In 2015, 2014 and 2013, 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 $33 million, $33 million and $58 million, respectively.

Volumetric Production Payments

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

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

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

As of December 31, 2015, our outstanding VPPs consisted of the following:

				Volume Sold			
VPP #	Date of VPP	Location	Proceeds	Oil	Natural Gas	NGL	Total
			($ in millions)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
10	March 2012	Anadarko Basin Granite Wash	$ 744	3.0	87	9.2	160
9	May 2011	Mid-Continent	853	1.7	138	4.8	177
4	December 2008	Anadarko and Arkoma Basins	412	0.5	95	—	98
3	August 2008	Anadarko Basin	600	—	93	—	93
2	May 2008	Texas, Oklahoma and Kansas	622	—	94	—	94
1	December 2007	Kentucky and West Virginia	1,100	—	208	—	208
			$ 4,331	5.2	715	14.0	830

The volumes produced on behalf of our VPP buyers during 2015, 2014 and 2013 were as follows:

	Year Ended December 31, 2015			
VPP #	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)
10	310.0	8.5	1,043.9	16.6
9	167.9	14.2	375.9	17.4
8[(a)]	—	36.5	—	36.5
4	42.5	8.0	—	8.2
3	—	6.4	—	6.4
2	—	4.0	—	4.0
1	—	13.3	—	13.3
	520.4	90.9	1,419.8	102.4

	Year Ended December 31, 2014			
VPP #	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)
10	403.0	10.6	1,296.5	20.7
9	187.5	15.4	411.0	19.0
8	—	60.1	—	60.1
6[(b)]	23.1	4.2	—	4.3
5[(b)]	16.5	4.6	—	4.7
4	48.1	9.0	—	9.2
3	—	7.2	—	7.2
2	—	6.2	—	6.2
1	—	13.8	—	13.8
	678.2	131.1	1,707.5	145.2

	Year Ended December 31, 2013			
VPP #	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)
10	547.0	13.5	1,509.0	25.8
9	213.2	17.0	455.7	21.0
8	—	68.1	—	68.1
6	24.0	4.8	—	4.9
5	25.4	7.5	—	7.7
4	54.7	10.2	—	10.5
3	—	8.1	—	8.1
2	—	10.3	—	10.3
1	—	14.5	—	14.5
	864.3	154.0	1,964.7	170.9

(a) VPP #8 expired in 2015.

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

The volumes remaining to be delivered on behalf of our VPP buyers as of December 31, 2015 were as follows:

		Volume Remaining as of December 31, 2015			
VPP #	**Term Remaining**	**Oil**	**Natural Gas**	**NGL**	**Total**
	(in months)	**(mmbbl)**	**(bcf)**	**(mmbbl)**	**(bcfe)**
10	74	1.0	29.6	3.6	57.4
9	62	0.7	59.0	1.6	72.4
4	12	—	7.3	—	7.6
3	43	—	17.5	—	17.5
2	40	—	9.8	—	9.8
1	84	—	78.3	—	78.3
		1.7	201.5	5.2	243.0

13. Spin-Off of Oilfield Services Business

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

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

- COO and certain of its subsidiaries entered into a $275 million senior secured revolving credit facility and a $400 million secured term loan, the proceeds of which were used to repay in full and terminate COO's then-existing credit facility.
- COO distributed to us its compression unit manufacturing business, its geosteering business and the proceeds from the sale of substantially all of its crude oil hauling business. See Note 16 for further discussion of the sale.
- We transferred to a subsidiary of COO, at carrying value, certain of our buildings and land, most of which COO had been leasing from us prior to the spin-off.
- COO issued $500 million of 6.5% Senior Notes due 2022 in a private placement and used the net proceeds to make a cash distribution of approximately $391 million to us, to repay a portion of outstanding indebtedness under the new revolving credit facility and for general corporate purposes.
- COO converted from a limited liability company into SSE, a publicly-traded corporation.
- We distributed all of SSE's outstanding shares to our shareholders, which resulted in SSE becoming an independent, publicly traded company.

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

In connection with the spin-off, we entered into several agreements to define the terms and conditions of the spin-off and our ongoing relationship with SSE after the spin-off, including a master separation agreement, a tax sharing agreement, an employee matters agreement, a transition services agreement, a services agreement and certain commercial agreements. These agreements, among other things, allocate responsibility for obligations arising before and after the distribution date, including obligations relating to taxes, employees, various transition services and oilfield services.

- The master separation agreement sets forth the agreements between SSE and Chesapeake regarding the principal transactions that were necessary to effect the spin-off and also sets forth other agreements that govern certain aspects of SSE's relationship with Chesapeake after completion of the spin-off.
- The tax sharing agreement governs the respective rights, responsibilities and obligations of SSE and Chesapeake with respect to tax liabilities and benefits, tax attributes, the preparation and filing of tax returns, the control of audits and other tax proceedings, and certain other matters regarding taxes.
- The employee matters agreement addresses employee compensation and benefit plans and programs, and other related matters in connection with the spin-off, including the treatment of holders of Chesapeake common stock options, restricted stock and performance share units, and the cooperation between SSE and Chesapeake in the sharing of employee information and maintenance of confidentiality. See Note 9 for additional information regarding the effect of the spin-off on outstanding equity compensation.
- The transition services agreement sets forth the terms on which we provide SSE certain services. Transition services include marketing and corporate communication, human resources, information technology, security, legal, risk management, tax, environmental health and safety, maintenance, internal audit, accounting, treasury and certain other services specified in the agreement. SSE pays Chesapeake a negotiated fee for providing those services. This agreement was terminated in 2015.
- The services agreement requires us to utilize, at market-based pricing, certain SSE pressure pumping services. See Note 4 for a summary of the terms of the services agreement.
- We have also entered into drilling agreements that are rig-specific daywork drilling contracts with terms ranging from three months to three years and at market-based rates. We have the right to terminate a drilling agreement in certain circumstances. As of December 31, 2015, the aggregate undiscounted minimum future payments under these drilling agreements were approximately $227 million.

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

14. Investments

A summary of our investments, including our approximate ownership percentage and carrying value as of December 31, 2015 and 2014, is presented below.

		Approximate Ownership %		Carrying Value	
	Accounting Method	December 31, 2015	December 31, 2014	December 31, 2015	December 31, 2014
				($ in millions)	
Sundrop Fuels, Inc.	Equity	56%	56%	$ 119	$ 130
FTS International, Inc. ...	Equity	30%	30%	—	116
Other	—	—%	—%	17	19
Total investments				$ 136	$ 265

Sundrop Fuels, Inc. Sundrop Fuels, Inc. (Sundrop), based in Longmont, Colorado, is a privately held cellulosic biofuels company that is constructing a nonfood biomass-based “green gasoline” plant. In 2015, we recorded a $20 million charge related to our share of Sundrop's net loss and $9 million of capitalized interest associated with the construction of Sundrop’s plant. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $87 million as of December 31, 2015 and will be amortized over the life of the plant once it is placed into service.

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

Sold Investments

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

Clean Energy Fuels Corp. In 2013, we sold all of our shares of Clean Energy Fuels Corp. (Clean Energy) common stock for cash proceeds of approximately $13 million. We recorded a $3 million gain related to the sale. In 2013, we sold our $100 million investment in convertible notes of Clean Energy for cash proceeds of $85 million. The buyer also assumed our commitment to purchase the third and final $50 million tranche of Clean Energy convertible notes. We recorded a $15 million loss related to this sale.

Gastar Exploration Ltd. In 2013, we sold our investment in Gastar Exploration Ltd. for cash proceeds of $10 million.

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

In 2013, we sold an equity investment for cash proceeds of $6 million and recorded a $5 million gain associated with the transaction.

15. Variable Interest Entities

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

Consolidated VIE

Chesapeake Granite Wash Trust. For a discussion of the formation, operations and presentation of the Trust, see *Noncontrolling Interests* in Note 8. The Trust is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Trust. Our ownership in the Trust and our obligations under the development agreement and related drilling support lien constitute variable interests. We have determined that we are the primary beneficiary of the Trust because (i) we have the power to direct the activities that most significantly impact the economic performance of the Trust via our obligations to perform under the development agreement, and (ii) as a result of the subordination and incentive thresholds applicable to the subordinated units we hold in the Trust, we have the obligation to absorb losses and the right to receive residual returns that potentially could be significant to the Trust. As a result, we consolidate the Trust in our financial statements, and the common units of the Trust owned by third parties are reflected as a noncontrolling interest.

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries, and the Trust is not a guarantor of any of Chesapeake's debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake; however, we have certain obligations to the Trust through the development agreement that are secured by a drilling support lien on our retained interest in the development wells up to a specified maximum amount recoverable by the Trust, which could result in the Trust acquiring all or a portion of our retained interest in the undeveloped portion of an area of mutual interest, if we do not meet our drilling commitment. In consolidation, as of December 31, 2015, $1 million of cash and cash equivalents, $488 million of proved oil and natural gas properties, $428 million of accumulated depreciation, depletion and amortization and $8 million of other current liabilities were attributable to the Trust. We have presented parenthetically on the face of the consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

Unconsolidated VIE

Mineral Acquisition Company I, L.P. In 2012, MAC-LP, L.L.C., a wholly owned non-guarantor unrestricted subsidiary of Chesapeake, entered into a partnership agreement with KKR Royalty Aggregator LLC (KKR) to form Mineral Acquisition Company I, L.P. The purpose of the partnership is to acquire mineral interests, or royalty interests carved out of mineral interests, in oil and natural gas basins in the continental United States. We are committed to acquire for our own account (outside the partnership) 10% of any acquisition agreed upon by the partnership up to a maximum of $25 million, and the partnership will acquire the remaining 90% up to a maximum of $225 million, funded entirely by KKR, making KKR the sole equity investor. We have significant influence over the decisions made by the partnership, as we hold two of five seats on the board of directors. We will receive proportionate distributions from the partnership of any cash received from royalties in excess of expenses paid, ranging from 7% to 22.5%. The partnership is considered a VIE because KKR's control over the partnership is disproportionate to its economic interest. This VIE remains unconsolidated as the power to direct the activities of the partnership is shared between the Company and KKR. We are using the equity method to account for this investment. The carrying value of our investment was $10 million as of December 31, 2015.

16. Other Property and Equipment

Other Property and Equipment

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

	December 31, 2015	December 31, 2014	Estimated Useful Life
	($ in millions)		(in years)
Buildings and improvements	$ 1,209	$ 1,242	10 – 39
Natural gas compressors[(a)]	483	551	3 – 20
Land	289	296	
Gathering systems and treating plants[(a)]	214	218	20
Other	732	776	2 – 20
Total other property and equipment, at cost	2,927	3,083	
Less: accumulated depreciation	(813)	(804)	
Total other property and equipment, net	$ 2,114	$ 2,279	

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

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, 2015, 2014 and 2013 is as follows:

	Years Ended December 31, 2015	2014	2013
	($ in millions)		
Buildings and land	$ 3	$ (2)	$ 27
Natural gas compressors	—	(195)	—
Gathering systems and treating plants	1	8	(326)
Oilfield services equipment	—	(7)	2
Other	—	(3)	(5)
Total net (gains) losses on sales of fixed assets	$ 4	$ (199)	$ (302)

Buildings and Land. The net losses in 2015, net gains in 2014 and the net losses in 2013 on sales of buildings and land were mainly from the sale of certain buildings and land located primarily in Oklahoma City and our Barnett Shale operating area.

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

Gathering Systems and Treating Plants. In 2013, we sold our wholly owned midstream subsidiary Mid-America Midstream Gas Services, L.L.C. to SemGas, L.P., a wholly owned subsidiary of SemGroup Corporation, for net proceeds of approximately $306 million. We recorded a $141 million gain associated with the transaction. In 2013, we also sold our wholly owned subsidiary Granite Wash Midstream Gas Services, L.L.C. to MarkWest Oklahoma Gas Company, L.L.C. (MW), a wholly owned subsidiary of MarkWest Energy Partners, L.P., for net proceeds of approximately $252 million. We recorded a $105 million gain associated with this transaction. The transaction with MW included long-term fixed fee arrangements for gas gathering, compression, treating and processing services in the Anadarko Basin. In 2013, we also sold our interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP for proceeds of approximately $134 million. We recorded a $55 million gain associated with this transaction.

Oilfield Services Equipment. In 2014, we sold substantially all of our crude oil hauling assets for approximately $44 million. We recorded a $23 million gain associated with the transaction. Also, in 2014, we sold 14 rigs for approximately $14 million and recorded a $14 million loss.

Assets Held for Sale

We are continuing to pursue the sale of buildings and land located primarily in Oklahoma, West Virginia and the Fort Worth, Texas area. Buildings and land are recorded within our other segment. These assets are being actively marketed, and we believe it is probable they will be sold over the next 12 months. As a result, these assets are reflected as held for sale as of December 31, 2015. 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, 2015 and 2014, we had $95 million and $93 million, respectively, of buildings and land, net of accumulated depreciation, classified as assets held for sale on our consolidated balance sheets.

17. Impairments

Impairments of Oil and Natural Gas Properties

On a quarterly basis, we analyze our unproved leasehold and transfer to proved properties leasehold that can be associated with proved reserves, leasehold that expired in the quarter and leasehold that is no longer part of our development strategy and will be abandoned. As commodity prices have decreased significantly over the past 12 months, we transferred, in 2015, noncore unproved leasehold in all of our operating areas having a cost of approximately $1.9 billion that would not be a part of our development strategy going forward.

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. During 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 $18.238 billion. During 2015, cash flow hedges which related to future periods, increased the ceiling test impairment by $176 million. Based on the first-day-of-the-month prices we have received over the 11 months ended February 1, 2016, we expect to record another material write-down in the carrying value of our oil and natural gas properties in the first quarter of 2016. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

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 loss 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, 2015, 2014 and 2013 is as follows:

	Years Ended December 31,		
	2015	2014	2013
		($ in millions)	
Natural gas compressors	$ 21	$ 11	$ —
Buildings and land	—	18	366
Gathering systems and treating plants	—	13	22
Oilfield services equipment	—	23	71
Other	173	23	87
Total impairments of fixed assets and other	$ 194	$ 88	$ 546

Natural Gas Compressors. In 2015, we recorded a $21 million impairment related to 465 compressors for the difference between the aggregate sales price of $40 million and the carrying value.

Buildings and Land. In 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. We recognized an impairment loss of $186 million on these assets for the difference between the carrying amount and fair value of the assets, less the anticipated costs to sell. Given the impairment losses associated with these assets, we tested other noncore buildings and land that we owned in the Oklahoma City area for recoverability. As a result of this test, we recognized an impairment loss of $69 million on these assets in 2013.

Due to a decrease in the estimated market prices of certain property classified as held for sale in the Fort Worth area, we recognized an additional impairment loss of $86 million in 2013. We tested other noncore surface land that we owned in the Fort Worth area for recoverability in 2013 and recognized an additional impairment loss of $10 million on these assets for the difference between the carrying amount and fair value of the assets.

Finally, we recorded an impairment loss of approximately $15 million on certain of our buildings and land outside of the Oklahoma City and Fort Worth areas in 2013. All the buildings and land for which impairment losses were recognized in 2015, 2014 and 2013 are included in our other segment.

Oilfield Services Equipment. In 2014, we purchased 31 leased rigs and equipment from various lessors for an aggregate purchase price of $140 million. In connection with these purchases, we paid $8 million in early lease termination costs, which are included in impairments of fixed assets and other in the consolidated statement of operations. In addition, we recognized an impairment loss of approximately $15 million related to leasehold improvements associated with these assets. The drilling rigs and equipment are included in our former oilfield services operating segment. In 2013, we purchased 23 leased rigs from various lessors for an aggregate purchase price of $141 million and paid approximately $22 million in early lease termination costs, which is included in impairments of fixed assets and other in the consolidated statement of operations. In addition, we impaired approximately $22 million related to leasehold improvements and other costs associated with these assets. In 2013, we also recognized $27 million of impairment losses on certain of our drilling rigs for the difference between the carrying amount and fair value, less the anticipated costs to sell. We estimated the fair value using prices expected to be received.

Other. In 2015, we recorded a $47 million loss contingency related to contract disputes. In 2015, we recorded a $22 million impairment of a note receivable as a result of the increased credit risk associated with declining commodity prices. In addition, under the terms of our joint venture agreements (see Note 12), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas. In 2015, we entered into a settlement with Total regarding our acreage maintenance commitment in our Barnett Shale joint venture and accrued a $70 million charge. In 2015, as a result of reductions in our planned drilling activity in response to declines in oil and natural gas prices, we terminated contracts with drilling contractors and incurred charges of $18 million. Further contract termination charges in subsequent quarters may occur if commodity prices remain low or continue to decline. The contract termination charges are included in our exploration and production operating segment. In 2014, we revised our estimate of our net acreage shortfall with Total under the terms of our Barnett Shale joint venture agreement and recorded a $22 million charge. See Note 4 for additional discussion regarding our net acreage maintenance commitments. In 2013, we recorded a $26 million charge for terminating a gas gathering agreement, a $28 million charge for the impairment of certain assets used to promote natural gas demand and $15 million for the termination of a contract drilling agreement with a third party.

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

18. Restructuring and Other Termination Costs

A summary of our restructuring and other termination costs for the years ended December 31, 2015, 2014 and 2013 is as follows:

	Years Ended December 31,		
	2015	2014	2013
	($ in millions)		
Restructuring charges under workforce reduction plan:			
Salary expense	$ 47	$ —	$ 20
Acceleration of stock-based compensation	—	—	45
Other termination benefits	8	—	1
Total restructuring changes under workforce reduction plan	55	—	66
Oilfield services spin-off costs:			
Transaction costs	—	17	—
Stock-based compensation adjustments for Chesapeake employees	—	5	—
Stock-based compensation forfeitures for SSE employees	—	(10)	—
Debt extinguishment costs	—	3	—
Total oilfield services spin-off costs	—	15	—
Termination benefits provided to Mr. McClendon:			
Salary and bonus expense	—	—	11
Acceleration of 2008 performance bonus clawback	—	—	11
Acceleration of stock-based compensation	—	—	22
Acceleration of performance share unit awards[(a)]	(8)	(8)	18
Estimated aircraft usage benefits	—	—	7
Total termination benefits provided to Mr. McClendon	(8)	(8)	69
Termination benefits provided to VSP participants:			
Salary and bonus expense	—	—	33
Acceleration of stock-based compensation	—	—	29
Other termination benefits	—	—	1
Total termination benefits provided to VSP participants	—	—	63
Other termination benefits[(a)]	(11)	—	50
Total restructuring and other termination costs	$ 36	$ 7	$ 248

(a) Amounts for the years ended December 31, 2015 and 2014 are primarily related to negative fair value adjustments to PSUs granted to former executives of the Company. For further discussion of our PSUs, see Note 9.

Workforce Reductions

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.

On September 9, 2013, we committed to a workforce reduction plan as part of a company-wide reorganization effort intended to reduce costs. The reduction was communicated to affected employees on various dates within the months of September and October, and all notifications were completed by October 11, 2013. The plan resulted in a reduction of approximately 900 employees. In connection with the reduction, we incurred a charge of approximately $66 million.

Oilfield Services Spin-Off

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

Other

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and CEO and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Mr. McClendon's departure from the Company was treated as a termination without cause under his employment agreement. On April 18, 2013, the Company and Mr. McClendon entered into a Founder Separation and Services Agreement, effective January 29, 2013, regarding his separation from employment and to facilitate the relationship between the Company and Mr. McClendon as joint working interest owners of oil and gas wells, leases and acreage. In 2013, we incurred charges of approximately $69 million related to Mr. McClendon's departure.

In December 2012, Chesapeake announced that it had offered a voluntary separation program (VSP) to certain employees as part of the Company's ongoing efforts to improve efficiencies and reduce costs. The VSP was offered to approximately 275 employees who met criteria based upon a combination of age and years of Chesapeake service, and 211 accepted prior to the expiration of the offer in February 2013. We recognized the expense related to their termination benefits over their remaining service period, which resulted in $63 million of expense for 2013.

During 2013, we also incurred charges of approximately $50 million related to other workforce reductions, including separations of executive officers other than the former CEO. Substantially all of the restructuring and other termination costs in 2013 are in the exploration and production operating segment.

We recognized a credit 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.

19. Fair Value Measurements

Recurring Fair Value Measurements

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

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

Financial Assets (Liabilities). The following table provides fair value measurement information for the above-noted financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2015 and 2014:

	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, 2015				
Financial Assets (Liabilities):				
Other current assets	$ 50	$ —	$ —	$ 50
Other current liabilities	(51)	—	—	(51)
Total	$ (1)	$ —	$ —	$ (1)
As of December 31, 2014				
Financial Assets (Liabilities):				
Other current assets	$ 57	$ —	$ —	$ 57
Other current liabilities	(58)	—	—	(58)
Total	$ (1)	$ —	$ —	$ (1)

See Note 3 for information regarding fair value measurement of our debt instruments. See Note 11 for information regarding fair value measurement of our derivatives.

Nonrecurring Fair Value Measurements

See Note 17 regarding nonrecurring fair value measurements.

20. Asset Retirement Obligations

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

	Years Ended December 31, 2015	Years Ended December 31, 2014
	($ in millions)	
Asset retirement obligations, beginning of period	$ 465	$ 405
Additions	6	29
Revisions[a]	13	101
Settlements and disposals	(34)	(92)
Accretion expense	23	22
Asset retirement obligations, end of period	473	465
Less current portion [b]	21	18
Asset retirement obligation, long-term	$ 452	$ 447

(a) Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settlement.

(b) Balance is included in other current liabilities on the consolidated balance sheet.

21. Major Customers and Segment Information

Sales to BP PLC constituted approximately 14% of our total revenues (before the effects of hedging) for the year ended December 31, 2015. Sales to Exxon Mobil Corporation constituted approximately 12% of our total revenues (before the effects of hedging) for the year ended December 31, 2014. There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the year ended December 31, 2013.

As of December 31, 2015, we have two reportable operating segments, each of which is managed separately because of the nature of its operations. The exploration and production operating segment is responsible for finding and producing oil, natural gas and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of oil, natural gas and NGL. In addition, prior to the spin-off of our oilfield services business in June 2014, our former oilfield services operating segment was responsible for drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties. Our former oilfield services segment's historical financial results for periods prior to the spin-off continue to be included in our historical financial results as a component of continuing operations, as reflected in the table below.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of oil, natural gas and NGL related to Chesapeake's ownership interests by our marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. These amounts totaled $4.372 billion, $8.565 billion and $7.570 billion for the years ended December 31, 2015, 2014 and 2013, respectively. Revenues generated by our former oilfield services operating segment for work performed for Chesapeake's exploration and production operating segment were reclassified to the full cost pool based on Chesapeake's ownership interest. Revenues reclassified totaled $544 million and $1.309 billion for the years ended December 31, 2014 and 2013, respectively. No income was recognized in our consolidated statements of operations related to oilfield services performed for Chesapeake-operated wells.

The following table presents selected financial information for Chesapeake's operating segments:

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
			($ in millions)			
Year Ended December 31, 2015						
Revenues	$ 5,391	$ 11,745	$ —	$ —	$ (4,372)	$ 12,764
Intersegment revenues	—	(4,372)	—	—	4,372	—
Total revenues	$ 5,391	$ 7,373	$ —	$ —	$ —	$ 12,764
Unrealized losses on commodity derivatives	$ 693	$ —	$ —	$ —	$ —	$ 693
Unrealized gains on marketing derivatives	$ —	$ (295)	$ —	$ —	$ —	$ (295)
Oil, natural gas, NGL and other depreciation, depletion and amortization	$ 2,170	$ 20	$ —	$ 39	$ —	$ 2,229
Impairment of oil and natural gas properties	$ 18,238	$ —	$ —	$ —	$ —	$ 18,238
Impairments of fixed assets and other	$ 126	$ 68	$ —	$ —	$ —	$ 194
Net gain (loss) on sales of fixed assets	$ 1	$ 1	$ —	$ 2	$ —	$ 4
Interest expense	$ (925)	$ (4)	$ —	$ 6	$ 606	$ (317)
Losses on investments	$ (3)	$ —	$ —	$ (93)	$ —	$ (96)
Impairments of investments	$ —	$ —	$ —	$ (53)	$ —	$ (53)
Gains on purchases or exchanges of debt	$ 279	$ —	$ —	$ —	$ —	$ 279
Income (Loss) Before Income Taxes	$ (19,619)	$ 117	$ —	$ (127)	$ 531	$ (19,098)
Total Assets	$ 11,819	$ 1,524	$ —	$ 4,325	$ (311)	$ 17,357
Capital Expenditures	$ 3,562	$ 42	$ —	$ 10	$ —	$ 3,614

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Year Ended December 31, 2014						
Revenues	$ 10,354	$ 20,790	$ 1,060	$ 30	$ (9,109)	$ 23,125
Intersegment revenues	—	(8,565)	(544)	—	9,109	—
Total revenues	$ 10,354	$ 12,225	$ 516	$ 30	$ —	$ 23,125
Unrealized gains on commodity derivatives	$ (1,394)	$ —	$ —	$ —	$ —	$ (1,394)
Unrealized gains on marketing derivatives	$ —	$ (3)	$ —	$ —	$ —	$ (3)
Oil, natural gas, NGL and other depreciation, depletion and amortization	$ 2,756	$ 38	$ 145	$ 42	$ (66)	$ 2,915
Impairments of fixed assets and other	$ 22	$ 24	$ 23	$ 19	$ —	$ 88
Net gain (loss) on sales of fixed assets	$ (2)	$ (187)	$ (8)	$ (2)	$ —	$ (199)
Interest expense	$ (709)	$ (21)	$ (42)	$ 3	$ 680	$ (89)
Losses on investments	$ 2	$ —	$ (1)	$ (76)	$ —	$ (75)
Impairments of investments	$ —	$ —	$ (5)	$ —	$ —	$ (5)
Net gain (loss) on sales of investments	$ (6)	$ —	$ —	$ 73	$ —	$ 67
Losses on purchases or exchanges of debt	$ (197)	$ —	$ —	$ —	$ —	$ (197)
Income (Loss) Before Income Taxes	$ 2,874	$ 326	$ (16)	$ (30)	$ 46	$ 3,200
Total Assets	$ 35,381	$ 1,978	$ —	$ 4,283	$ (891)	$ 40,751
Capital Expenditures	$ 6,173	$ 298	$ 158	$ 38	$ —	$ 6,667

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Year Ended December 31, 2013						
Revenues	$ 8,626	$ 17,129	$ 2,188	$ 29	$ (8,892)	$ 19,080
Intersegment revenues	—	(7,570)	(1,309)	(13)	8,892	—
Total revenues	$ 8,626	$ 9,559	$ 879	$ 16	$ —	$ 19,080
Unrealized gains on commodity derivatives	$ (228)	$ —	$ —	$ —	$ —	$ (228)
Oil, natural gas, NGL and other depreciation, depletion and amortization	$ 2,674	$ 46	$ 289	$ 49	$ (155)	$ 2,903
Impairments of fixed assets and other	$ 27	$ 50	$ 75	$ 394	$ —	$ 546
Net gain (loss) on sales of fixed assets	$ 2	$ (329)	$ (1)	$ 26	$ —	$ (302)
Interest expense	$ (918)	$ (24)	$ (82)	$ (74)	$ 871	$ (227)
Losses on investments	$ 3	$ —	$ —	$ (219)	$ —	$ (216)
Impairments of investments	$ —	$ —	$ (1)	$ (10)	$ 1	$ (10)
Net gain (loss) on sales of investments	$ —	$ —	$ —	$ (7)	$ —	$ (7)
Losses on purchases or exchanges of debt	$ (193)	$ —	$ —	$ —	$ —	$ (193)
Income (Loss) Before Income Taxes	$ 2,997	$ 511	$ (51)	$ (727)	$ (1,288)	$ 1,442
Total Assets	$ 35,341	$ 2,430	$ 2,018	$ 5,750	$ (3,757)	$ 41,782
Capital Expenditures	$ 6,198	$ 299	$ 272	$ 421	$ —	$ 7,190

22. 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. Our former oilfield services subsidiaries were separately capitalized and were not guarantors of our debt obligations.

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, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013. 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, 2015
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 928	$ 2	$ 1	$ (106)	$ 825
Other current assets	87	1,561	7	—	1,655
Intercompany receivable, net	24,789	—	434	(25,223)	—
Total Current Assets	25,804	1,563	442	(25,329)	2,480
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties, at cost based on full cost accounting, net	—	11,861	69	159	12,089
Other property and equipment, net	—	2,113	1	—	2,114
Property and equipment held for sale, net	—	95	—	—	95
Total Property and Equipment, Net	—	14,069	70	159	14,298
LONG-TERM ASSETS:					
Other long-term assets	74	495	10	—	579
Investments in subsidiaries and intercompany advances	(12,349)	771	—	11,578	—
TOTAL ASSETS	$ 13,529	$ 16,898	$ 522	$ (13,592)	$ 17,357
CURRENT LIABILITIES:					
Current liabilities	$ 921	$ 2,862	$ 8	$ (106)	$ 3,685
Intercompany payable, net	—	25,580	—	(25,580)	—
Total Current Liabilities	921	28,442	8	(25,686)	3,685
LONG-TERM LIABILITIES:					
Long-term debt, net	10,354	—	—	—	10,354
Other long-term liabilities	116	805	—	—	921
Total Long-Term Liabilities	10,470	805	—	—	11,275
EQUITY:					
Chesapeake stockholders' equity	2,138	(12,349)	514	11,835	2,138
Noncontrolling interests	—	—	—	259	259
Total Equity	2,138	(12,349)	514	12,094	2,397
TOTAL LIABILITIES AND EQUITY	$ 13,529	$ 16,898	$ 522	$ (13,592)	$ 17,357

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 4,100	$ 2	$ 84	$ (78)	$ 4,108
Restricted cash	—	—	38	—	38
Other current assets	55	3,174	93	—	3,322
Intercompany receivable, net	24,527	—	341	(24,868)	—
Total Current Assets	28,682	3,176	556	(24,946)	7,468
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties, at cost based on full cost accounting, net	—	28,358	1,112	673	30,143
Other property and equipment, net	—	2,276	3	—	2,279
Property and equipment held for sale, net	—	93	—	—	93
Total Property and Equipment, Net	—	30,727	1,115	673	32,515
LONG-TERM ASSETS:					
Other long-term assets	153	618	26	(29)	768
Investments in subsidiaries and intercompany advances	126	467	—	(593)	—
TOTAL ASSETS	$ 28,961	$ 34,988	$ 1,697	$ (24,895)	$ 40,751
CURRENT LIABILITIES:					
Current liabilities	$ 761	$ 4,915	$ 58	$ (78)	$ 5,656
Intercompany payable, net	—	24,940	—	(24,940)	—
Total Current Liabilities	761	29,855	58	(25,018)	5,656
LONG-TERM LIABILITIES:					
Long-term debt, net	11,154	—	—	—	11,154
Deferred income tax liabilities	31	3,917	244	200	4,392
Other long-term liabilities	112	1,090	142	—	1,344
Total Long-Term Liabilities	11,297	5,007	386	200	16,890
EQUITY:					
Chesapeake stockholders' equity	16,903	126	1,253	(1,379)	16,903
Noncontrolling interests	—	—	—	1,302	1,302
Total Equity	16,903	126	1,253	(77)	18,205
TOTAL LIABILITIES AND EQUITY	$ 28,961	$ 34,988	$ 1,697	$ (24,895)	$ 40,751

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2015
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 5,252	$ 139	$ —	$ 5,391
Marketing, gathering and compression	—	7,373	—	—	7,373
Total Revenues	—	12,625	139	—	12,764
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	1,019	27	—	1,046
Oil, natural gas and NGL gathering, processing and transportation	—	2,094	25	—	2,119
Production taxes	—	97	2	—	99
Marketing, gathering and compression	—	7,129	1	—	7,130
General and administrative	1	231	3	—	235
Restructuring and other termination costs	—	36	—	—	36
Provision for legal contingencies	339	14	—	—	353
Oil, natural gas and NGL depreciation, depletion and amortization	—	2,051	69	(21)	2,099
Depreciation and amortization of other assets	—	130	—	—	130
Impairment of oil and natural gas properties	—	18,224	472	(458)	18,238
Impairments of fixed assets and other	—	194	—	—	194
Net gains on sales of fixed assets	—	4	—	—	4
Total Operating Expenses	340	31,223	599	(479)	31,683
LOSS FROM OPERATIONS	(340)	(18,598)	(460)	479	(18,919)
OTHER INCOME (EXPENSE):					
Interest expense	(721)	(198)	—	602	(317)
Losses on investments	—	(96)	—	—	(96)
Impairments of investments	—	(53)	—	—	(53)
Gains on purchases or exchanges of debt	279	—	—	—	279
Other income (expense)	140	10	1	(143)	8
Equity in net earnings (losses) of subsidiary	(14,197)	(402)	—	14,599	—
Total Other Expense	(14,499)	(739)	1	15,058	(179)
LOSS BEFORE INCOME TAXES	(14,839)	(19,337)	(459)	15,537	(19,098)
INCOME TAX EXPENSE (BENEFIT)	(154)	(4,421)	(107)	219	(4,463)
NET LOSS	(14,685)	(14,916)	(352)	15,318	(14,635)
Net income attributable to noncontrolling interests	—	—	—	(50)	(50)
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	(14,685)	(14,916)	(352)	15,268	(14,685)
Other comprehensive income	21	23	—	—	44
COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE	$ (14,664)	$ (14,893)	$ (352)	$ 15,268	$ (14,641)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 9,899	$ 458	$ (3)	$ 10,354
Marketing, gathering and compression	—	12,220	5	—	12,225
Oilfield services	—	41	983	(478)	546
Total Revenues	—	22,160	1,446	(481)	23,125
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	1,166	42	—	1,208
Oil, natural gas and NGL gathering, processing and transportation	—	2,134	40	—	2,174
Production taxes	—	227	5	—	232
Marketing, gathering and compression	—	12,232	4	—	12,236
Oilfield services	—	53	769	(391)	431
General and administrative	—	273	49	—	322
Restructuring and other termination costs	—	4	3	—	7
Provision for legal contingencies	100	134	—	—	234
Oil, natural gas and NGL depreciation, depletion and amortization	—	2,523	162	(2)	2,683
Depreciation and amortization of other assets	—	153	143	(64)	232
Impairment of oil and natural gas properties	—	—	349	(349)	—
Impairments of fixed assets and other	—	65	23	—	88
Net gains on sales of fixed assets	—	(192)	(7)	—	(199)
Total Operating Expenses	100	18,772	1,582	(806)	19,648
INCOME (LOSS) FROM OPERATIONS	(100)	3,388	(136)	325	3,477
OTHER INCOME (EXPENSE):					
Interest expense	(657)	(37)	(42)	647	(89)
Losses on investments	—	(77)	—	2	(75)
Impairments of investments	—	—	(5)	—	(5)
Net gain of sales of investments	—	67	—	—	67
Losses on purchases or exchanges of debt	(195)	(2)	—	—	(197)
Other income (expense)	502	198	(2)	(676)	22
Equity in net earnings (losses) of subsidiary	2,206	(258)	—	(1,948)	—
Total Other Income (Expense)	1,856	(109)	(49)	(1,975)	(277)
INCOME (LOSS) BEFORE INCOME TAXES	1,756	3,279	(185)	(1,650)	3,200
INCOME TAX EXPENSE (BENEFIT)	(161)	1,264	(66)	107	1,144
NET INCOME (LOSS)	1,917	2,015	(119)	(1,757)	2,056
Net income attributable to noncontrolling interests	—	—	—	(139)	(139)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,917	2,015	(119)	(1,896)	1,917
Other comprehensive income	1	18	—	—	19
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 1,918	$ 2,033	$ (119)	$ (1,896)	$ 1,936

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 8,013	$ 553	$ 60	$ 8,626
Marketing, gathering and compression	—	9,547	12	—	9,559
Oilfield services	—	221	1,836	(1,162)	895
Total Revenues	—	17,781	2,401	(1,102)	19,080
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	1,112	47	—	1,159
Oil, natural gas and NGL gathering, processing and transportation	—	1,574	—	—	1,574
Production taxes	—	222	7	—	229
Marketing, gathering and compression	—	9,455	6	—	9,461
Oilfield services	—	239	1,434	(937)	736
General and administrative	—	375	83	(1)	457
Restructuring and other termination costs	—	244	4	—	248
Oil, natural gas and NGL depreciation, depletion and amortization	—	2,336	253	—	2,589
Depreciation and amortization of other assets	—	180	281	(147)	314
Impairment of oil and natural gas properties	—	(2)	313	(311)	—
Impairments of fixed assets and other	—	417	129	—	546
Net gains on sales of fixed assets	—	(301)	(1)	—	(302)
Total Operating Expenses	—	15,851	2,556	(1,396)	17,011
INCOME (LOSS) FROM OPERATIONS	—	1,930	(155)	294	2,069
OTHER INCOME (EXPENSE):					
Interest expense	(921)	(4)	(85)	783	(227)
Losses on investments	—	(216)	—	—	(216)
Impairments of investments	—	(9)	(1)	—	(10)
Net loss on sales of investments	—	(7)	—	—	(7)
Losses on purchases or exchanges of debt	(70)	(123)	—	—	(193)
Other income (expense)	3,979	(603)	13	(3,363)	26
Equity in net earnings (losses) of subsidiary	(1,129)	(383)	—	1,512	—
Total Other Income (Expense)	1,859	(1,345)	(73)	(1,068)	(627)
INCOME (LOSS) BEFORE INCOME TAXES	1,859	585	(228)	(774)	1,442
INCOME TAX EXPENSE (BENEFIT)	1,135	369	(87)	(869)	548
NET INCOME (LOSS)	724	216	(141)	95	894
Net income attributable to noncontrolling interests	—	—	—	(170)	(170)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	724	216	(141)	(75)	724
Other comprehensive income (loss)	3	19	(2)	—	20
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 727	$ 235	$ (143)	$ (75)	$ 744

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2015
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ —	$ 1,142	$ 110	$ (18)	$ 1,234
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(3,032)	(63)	—	(3,095)
Acquisitions of proved and unproved properties	—	(529)	(4)	—	(533)
Proceeds from divestitures of proved and unproved properties	—	152	37	—	189
Additions to other property and equipment	—	(148)	5	—	(143)
Other investing activities	—	67	52	12	131
Net Cash Used In Investing Activities	—	(3,490)	27	12	(3,451)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Cash paid to repurchase noncontrolling interest of CHK C-T	—	—	(143)	—	(143)
Cash paid to purchase debt	(508)	—	—	—	(508)
Other financing activities	(789)	473	(77)	(22)	(415)
Intercompany advances, net	(1,875)	1,875	—	—	—
Net Cash Provided by (Used In) Financing Activities	(3,172)	2,348	(220)	(22)	(1,066)
Net decrease in cash and cash equivalents	(3,172)	—	(83)	(28)	(3,283)
Cash and cash equivalents, beginning of period	4,100	2	84	(78)	4,108
Cash and cash equivalents, end of period	$ 928	$ 2	$ 1	$ (106)	$ 825

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2014
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ —	$ 4,201	$ 462	$ (29)	$ 4,634
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(4,445)	(136)	—	(4,581)
Acquisitions of proved and unproved properties	—	(1,306)	(5)	—	(1,311)
Proceeds from divestitures of proved and unproved properties	—	5,812	1	—	5,813
Additions to other property and equipment	—	(480)	(246)	—	(726)
Other investing activities	—	1,199	60	—	1,259
Net Cash Provided By (Used In) Investing Activities	—	780	(326)	—	454
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	6,689	717	—	7,406
Payments on credit facilities borrowings	—	(6,689)	(1,099)	—	(7,788)
Proceeds from issuance of senior notes, net of discount and offering costs	2,966	—	494	—	3,460
Proceeds from issuance of oilfield services term loan, net of issuance costs	—	—	394	—	394
Cash paid to purchase debt	(3,362)	—	—	—	(3,362)
Other financing activities	(439)	(1,278)	(169)	(41)	(1,927)
Intercompany advances, net	4,136	(3,709)	(427)	—	—
Net Cash Provided By (Used In) Financing Activities	3,301	(4,987)	(90)	(41)	(1,817)
Net increase (decrease) in cash and cash equivalents	3,301	(6)	46	(70)	3,271
Cash and cash equivalents, beginning of period	799	8	38	(8)	837
Cash and cash equivalents, end of period	$ 4,100	$ 2	$ 84	$ (78)	$ 4,108

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net Cash Provided By Operating Activities	$ —	$ 4,218	$ 439	$ (43)	$ 4,614
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(4,838)	(766)	—	(5,604)
Acquisitions of proved and unproved properties	—	(1,378)	346	—	(1,032)
Proceeds from divestitures of proved and unproved properties	—	3,466	1	—	3,467
Additions to other property and equipment	—	(271)	(701)	—	(972)
Other investing activities	—	246	765	163	1,174
Net Cash Used In Investing Activities	—	(2,775)	(355)	163	(2,967)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	6,452	1,217	—	7,669
Payments on credit facilities borrowings	—	(6,452)	(1,230)	—	(7,682)
Proceeds from issuance of senior notes, net of discount and offering costs	2,274	—	—	—	2,274
Cash paid to purchase debt	(2,141)	—	—	—	(2,141)
Proceeds from sales of noncontrolling interests	—	—	6	—	6
Other financing activities	1,819	(2,897)	(17)	(128)	(1,223)
Intercompany advances, net	(1,381)	1,462	(81)	—	—
Net Cash Provided By (Used In) Financing Activities	571	(1,435)	(105)	(128)	(1,097)
Net increase (decrease) in cash and cash equivalents	571	8	(21)	(8)	550
Cash and cash equivalents, beginning of period	228	—	59	—	287
Cash and cash equivalents, end of period	$ 799	$ 8	$ 38	$ (8)	$ 837

23. Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration the company expects to receive in the exchange. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early application not permitted. In July 2015, the FASB approved a one-year deferral of the effective date as well as permission to early adopt the new revenue recognition standard as of the original effective date. We are evaluating the impact of this guidance on our consolidated financial statements.

In April 2015, the FASB issued an accounting standards update on the presentation of debt issuance costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs is not affected by the update. For public entities, the guidance is effective for reporting periods beginning after December 15, 2015, and it is not expected to have a material impact on our consolidated financial statements. In August 2015, the FASB issued an accounting standards update which allows for debt issuance costs related to line-of-credit arrangements to be presented as an asset and subsequently amortized ratably over the term of the line-of-credit arrangements, regardless of whether there are any outstanding borrowings on the line-of-credit arrangements. For public entities, the guidance is effective for reporting periods beginning after December 15, 2015, and it is not expected to have a material impact on our consolidated financial statements.

24. Subsequent Events

Subsequent to December 31, 2015, we repurchased in the open market approximately $60 million of our outstanding 2.5% Contingent Convertible Notes due 2037 for $32 million, $122 million of our 3.25% Senior Notes due 2016 for $115 million and $2 million of our 6.5% Senior Notes due 2017 for $1 million.

Subsequent to December 31, 2015, we closed certain asset divestitures for proceeds of approximately $138 million. We also executed sales agreements for other asset divestitures with expected proceeds of approximately $586 million. The asset divestitures cover various operating areas.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
SUPPLEMENTARY INFORMATION

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2015 and 2014 are as follows:

	Quarters Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
	($ in millions except per share data)			
Total revenues	$ 3,218	$ 3,521	$ 3,376	$ 2,649
Gross profit[a]	$ (5,040)	$ (5,507)	$ (5,453)	$ (2,919)
Net loss attributable to Chesapeake	$ (3,739)	$ (4,108)	$ (4,653)	$ (2,185)
Net loss available to common stockholders	$ (3,782)	$ (4,151)	$ (4,695)	$ (2,228)
Net loss per common share:				
Basic	$ (5.72)	$ (6.27)	$ (7.08)	$ (3.36)
Diluted	$ (5.72)	$ (6.27)	$ (7.08)	$ (3.36)

	Quarters Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
	($ in millions except per share data)			
Total revenues	$ 5,557	$ 5,656	$ 6,223	$ 5,689
Gross profit[a]	$ 733	$ 610	$ 1,174	$ 960
Net income attributable to Chesapeake	$ 425	$ 191	$ 662	$ 639
Net income available to common stockholders	$ 374	$ 144	$ 169	$ 586
Net earnings per common share:				
Basic	$ 0.57	$ 0.22	$ 0.26	$ 0.89
Diluted	$ 0.54	$ 0.22	$ 0.26	$ 0.81

(a) Total revenue less operating expenses. Includes a $18.238 billion ceiling test write-down on our oil and natural gas properties for the year ended December 31, 2015.

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

Net Capitalized Costs

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

	December 31,	
	2015	2014
	($ in millions)	
Oil and oil and natural gas properties:		
Proved	$ 63,843	$ 58,594
Unproved	6,798	9,788
Total	70,641	68,382
Less accumulated depreciation, depletion and amortization	(58,552)	(38,238)
Net capitalized costs	$ 12,089	$ 30,144

Unproved properties not subject to amortization as of December 31, 2015, 2014 and 2013 consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. We capitalized approximately $410 million, $604 million and $815 million of interest during 2015, 2014 and 2013, 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,		
	2015	2014	2013
		($ in millions)	
Acquisition of Properties:			
Proved properties	$ —	$ 214	$ 22
Unproved properties	454	1,224	997
Exploratory costs	112	421	699
Development costs	2,941	4,204	4,888
Costs incurred[(a)(b)]	$ 3,507	$ 6,063	$ 6,606

(a) Exploratory and development costs are net of $51 million, $679 million and $884 million in drilling and completion carries received from our joint venture partners during 2015, 2014 and 2013, respectively.

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

Capitalized interest	$ 410	$ 604	$ 815
Asset retirement obligations	$ (15)	$ 39	$ 7

In 2015, we invested approximately $720 million, net of drilling and completion cost carries of $18 million, to convert 67 mmboe of PUDs to proved developed reserves.

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

Chesapeake's results of operations from oil, natural gas and NGL producing activities are presented below for 2015, 2014 and 2013. 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,		
	2015	2014	2013
		($ in millions)	
Oil, natural gas and NGL sales	$ 5,391	$ 10,354	$ 8,626
Oil, natural gas and NGL production expenses	(1,046)	(1,208)	(1,159)
Oil, natural gas and NGL gathering, processing and transportation expenses	(2,119)	(2,174)	(1,574)
Production taxes	(99)	(232)	(229)
Impairment of oil and natural gas properties	(18,238)	—	—
Depletion and depreciation	(2,099)	(2,683)	(2,589)
Imputed income tax provision[(a)]	6,683	(1,485)	(1,169)
Results of operations from oil, natural gas and NGL producing activities	$ (11,527)	$ 2,572	$ 1,906

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

Oil, Natural Gas and NGL Reserve Quantities

Chesapeake's petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2015, 2014 and 2013. Independent petroleum engineering firms estimated an aggregate of 59%, 79% and 81% of our estimated proved reserves (by volume) as of December 31, 2015, 2014 and 2013, respectively, as set forth below.

	December 31,		
	2015	2014	2013
Ryder Scott Company, L.P.	36%	54%	51%
PetroTechnical Services, Division of Schlumberger Technology Corporation	23%	25%	30%

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 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 2015, 2014 and 2013.

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
December 31, 2015				
Proved reserves, beginning of period	420.8	10,692	266.3	2,469
Extensions, discoveries and other additions	61.1	805	35.3	231
Revisions of previous estimates	(110.0)	(4,191)	(75.8)	(885)
Production	(41.6)	(1,070)	(28.0)	(248)
Sale of reserves-in-place	(16.6)	(195)	(14.3)	(63)
Purchase of reserves-in-place	—	—	—	—
Proved reserves, end of period[a]	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

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
December 31, 2014				
Proved reserves, beginning of period	423.8	11,734	299.0	2,678
Extensions, discoveries and other additions	108.6	1,567	78.2	448
Revisions of previous estimates	(51.1)	(129)	21.3	(51)
Production	(42.3)	(1,095)	(33.1)	(258)
Sale of reserves-in-place	(23.3)	(1,421)	(101.7)	(362)
Purchase of reserves-in-place	5.1	36	2.6	14
Proved reserves, end of period[c]	420.8	10,692	266.3	2,469
Proved developed reserves:				
Beginning of period	201.3	8,584	177.1	1,809
End of period	229.3	8,615	198.5	1,864
Proved undeveloped reserves:				
Beginning of period	222.5	3,150	121.9	869
End of period[b]	191.5	2,077	67.8	605
December 31, 2013				
Proved reserves, beginning of period	495.5	10,933	297.3	2,615
Extensions, discoveries and other additions	96.3	2,160	68.0	524
Revisions of previous estimates	(61.1)	388	(32.9)	(30)
Production	(41.1)	(1,095)	(20.9)	(244)
Sale of reserves-in-place	(66.4)	(657)	(13.1)	(189)
Purchase of reserves-in-place	0.6	5	0.6	2
Proved reserves, end of period[d]	423.8	11,734	299.0	2,678
Proved developed reserves:				
Beginning of period	162.9	7,174	132.1	1,491
End of period	201.3	8,584	177.1	1,809
Proved undeveloped reserves:				
Beginning of period	332.6	3,759	165.2	1,124
End of period[b]	222.5	3,150	121.9	869

(a) Includes 1 mmbbls of oil, 32 bcf of natural gas and 3 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 1 mmbbls of oil, 16 bcf of natural gas and 2 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

(b) As of December 31, 2015, 2014 and 2013, there were no PUDs that had remained undeveloped for five years or more.

(c) Includes 2 mmbbls of oil, 46 bcf of natural gas and 5 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 1 mmbbls of oil, 22 bcf of natural gas and 2 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

(d) Includes 2 mmbbls of oil, 61 bcf of natural gas and 6 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 1 mmbbls of oil, 30 bcf of natural gas and 3 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

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 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 to previous estimates. The oil and natural gas prices used in computing our reserves as of December 31, 2015 were $50.28 per bbl and $2.58 per mcf, respectively, before price differentials.

During 2014, we acquired approximately 14 mmboe of proved reserves through purchases of oil and natural gas properties for consideration of $168 million, and we sold 362 mmboe of proved reserves for approximately $4.7 billion. We recorded downward revisions of 51 mmboe, which was comprised of a 78 mmboe reduction of previous estimates partially offset by a 27 mmboe increase resulting primarily from higher natural gas prices in 2014. The oil and natural gas prices used in computing our reserves as of December 31, 2014 were $94.98 per bbl and $4.35 per mcf, respectively, before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2014 were $89.09 per barrel of oil, $2.68 per mcf of natural gas and $24.10 per barrel of NGL.

During 2013, we acquired approximately 2 mmboe of proved reserves through purchases of oil and natural gas properties for consideration of $22 million, and we sold 189 mmboe of proved reserves for approximately $1.621 billion. During 2013, we recorded downward revisions of 30 mmboe to the December 31, 2012 estimates of our reserves. Included in the revisions were 162 mmboe of upward revisions resulting from higher oil, natural gas and NGL prices in 2013 and 192 mmboe of downward revisions resulting from changes to previous estimates. Higher prices increase the economic lives of the underlying oil and natural gas properties and thereby increase the estimated future reserves. The oil and natural gas prices used in computing our reserves as of December 31, 2013 were $96.82 per bbl and $3.67 per mcf, respectively, before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2013 were $95.89 per barrel of oil, $2.37 per mcf of natural gas and $25.78 per barrel of NGL. Included in the non-price revisions were 355 mmboe of downward revisions to our estimated PUD reserves, offset by 163 mmboe of upward revisions for performance.

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, 2015, 2014 and 2013 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of oil, natural gas and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for that year. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

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

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

	Years Ended December 31,		
	2015	2014	2013
		($ in millions)	
Future cash inflows	$ 20,247 [(a)]	$ 72,557 [(b)]	$ 76,094 [(c)]
Future production costs	(7,391)	(17,036)	(18,196)
Future development costs	(1,518)	(7,556)	(9,563)
Future income tax provisions	(228)	(12,494)	(12,196)
Future net cash flows	11,110	35,471	36,139
Less effect of a 10% discount factor	(6,417)	(18,338)	(18,749)
Standardized measure of discounted future net cash flows[(d)]	$ 4,693	$ 17,133	$ 17,390

(a) Calculated using prices of $5.28 per bbl of oil and $2.58 per mcf of natural gas, before field differentials.

(b) Calculated using prices of $94.98 per bbl of oil and $4.35 per mcf of natural gas, before field differentials.

(c) Calculated using prices of $96.82 per bbl of oil and $3.67 per mcf of natural gas, before field differentials.

(d) Excludes future cash inflows attributable to production volumes sold to VPP buyers and includes future cash outflows attributable to the costs of production. See Note 12.

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

	Years Ended December 31,		
	2015	2014	2013
		($ in millions)	
Standardized measure, beginning of period[(a)]	$ 17,133	$ 17,390	$ 14,666
Sales of oil and natural gas produced, net of production costs and gathering, processing and transportation[(b)]	(1,503)	(5,722)	(5,535)
Net changes in prices and production costs	(18,070)	(634)	2,021
Extensions and discoveries, net of production and development costs	1,005	5,156	6,008
Changes in future development costs	3,198	1,946	1,287
Development costs incurred during the period that reduced future development costs	873	1,178	1,582
Revisions of previous quantity estimates	(3,472)	(715)	(805)
Purchase of reserves-in-place	1	215	26
Sales of reserves-in-place	(938)	(1,788)	(1,976)
Accretion of discount	2,201	2,168	1,777
Net change in income taxes	4,845	(593)	(1,180)
Changes in production rates and other	(580)	(1,468)	(481)
Standardized measure, end of period[(a)(c)(d)]	$ 4,693	$ 17,133	$ 17,390

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

(b) Excluding gains (losses) on derivatives.

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

(d) The standardized measure of discounted future net cash flows does not include estimated future cash inflows attributable to future production of VPP volumes sold and does include estimated future cash outflows attributable to the costs of future production of VPP volumes sold.

ITEM 9. ***Changes In and Disagreements with Accountants on Accounting and Financial Disclosure***

Not applicable.

ITEM 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Exchange Act Rule 13a–15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2015.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended December 31, 2015, which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. ***Other Information***

On February 22, 2016, Louis A. Raspino informed the Company of his decision to resign from his position as a director effective March 10, 2016 in order to devote more time to his new position as Chairman of Clarion Offshore Partners, a global investment platform formed in partnership with Blackstone. Mr. Raspino has served as a director of Chesapeake since March 2013. Mr. Raspino served as Chairman of the Audit Committee of the Board of Directors. Mr. Raspino's decision to resign from the Board of Directors was not the result of any disagreement with the Company on any matter relating to its operations, policies or practices.

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, 2016 (the "2016 Proxy Statement").

ITEM 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the 2016 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 2016 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 2016 Proxy Statement.

ITEM 14. ***Principal Accountant Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the 2016 Proxy Statement.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

(a) The following financial statements, financial statement schedules and exhibits are filed as a part of this report:

1. *Financial Statements*. Chesapeake's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules*. No financial statement schedules are applicable or required.
3. *Exhibits*. The exhibits listed below in the Index of Exhibits (following the signatures page) are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION

Date: February 25, 2016

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 25, 2016
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2016
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President – Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 25, 2016
/s/ R. BRAD MARTIN **R. Brad Martin**	Chairman of the Board	February 25, 2016
/s/ ARCHIE W. DUNHAM **Archie W. Dunham**	Director and Chairman Emeritus	February 25, 2016
/s/ VINCENT J. INTRIERI **Vincent J. Intrieri**	Director	February 25, 2016
/s/ JOHN J. LIPINSKI **John J. Lipinski**	Director	February 25, 2016
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	February 25, 2016
/s/ FREDRIC M. POSES **Frederic M. Poses**	Director	February 25, 2016
/s/ KIMBERLY K. QUERREY **Kimberly K. Querrey**	Director	February 25, 2016
/s/ LOUIS A. RASPINO **Louis A. Raspino**	Director	February 25, 2016
/s/ THOMAS L. RYAN **Thomas L. Ryan**	Director	February 25, 2016

INDEX OF EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
2.1.1*	Purchase and Sale Agreement by and between Chesapeake Appalachia, L.L.C. and Southwestern Energy Production Company dated October 14, 2014.	10-K	001-13726	2.1.1	2/27/2015	
2.1.2*	Amendment to Purchase and Sale Agreement by and between Chesapeake Appalachia, L.L.C. and SWN Production Company, LLC (formerly Southwestern Energy Production Company) dated December 22, 2014.	10-K	001-13726	2.1.2	2/27/2015	
2.1.3	Settlement Agreement by and between Chesapeake Appalachia, L.L.C. and SWN Production Company, LLC (formerly Southwestern Energy Production Company) dated December 22, 2014.	10-K	001-13726	2.1.3	2/27/2015	
3.1.1	Chesapeake's Restated Certificate of Incorporation.	10-Q	001-13726	3.1.1	8/6/2014	
3.1.2	Certificate of 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 August 16, 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 6.5% Senior Notes due 2017.	8-K	001-13726	4.1	8/16/2005	
4.2**	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.12.1	11/15/2005	
4.3**	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% Senior Notes due 2017.	8-K	001-13726	4.1	12/6/2006	

4.4**	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.5% Contingent Convertible Senior Notes due 2037.	8-K	001-13726	4.1	5/15/2007
4.5**	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	5/29/2008
4.6**	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
4.7.1**	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
4.7.2	First Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010
4.7.3	Second Supplemental Indenture, dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010
4.7.4	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010 with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011
4.7.5	Fourteenth Supplemental Indenture dated March 18, 2013 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated as of August 2, 2010.	S-3	333-168509	4.17	3/18/2013
4.7.6	Fifteenth Supplemental Indenture dated April 1, 2013 to Indenture dated as of August 2, 2010 with respect to 3.25% Senior Notes due 2016.	8-A	001-13726	4.2	4/8/2013
4.7.7	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
4.7.8	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
4.8.1**	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

4.8.2	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
4.8.3	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
4.9	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
4.10.1**	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.	8-K	001-13726	10.1	12/16/2014
4.10.2	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
4.10.3	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
4.11	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
4.12	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
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†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan, effective January 1, 2016.					X
10.4†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.	10-K	001-13726	10.16	3/1/2013	
10.5†	Employment Agreement dated as of May 20, 2013 between Robert D. Lawler and Chesapeake Energy Corporation.	8-K	001-13726	10.1	5/23/2013	
10.6†	Employment Agreement dated as of January 1, 2016 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.	8-K	001-13726	10.1	1/6/2016	
10.7†	Employment Agreement dated as of January 1, 2016 between James R. Webb and Chesapeake Energy Corporation.	8-K	001-13726	10.2	1/6/2016	
10.8†	Employment Agreement dated as of January 1, 2016 between M. Christopher Doyle and Chesapeake Energy Corporation.	8-K	001-13726	10.3	1/6/2016	

10.9†	Employment Agreement dated as of January 1, 2016 between Mikell Jason Pigott and Chesapeake Energy Corporation.	8-K	001-13726	10.4	1/6/2016	
10.10†	Employment Agreement dated as of May 21, 2015 between Frank Patterson and Chesapeake Energy Corporation.	10-Q	001-13726	10.1	8/5/2015	
10.11†	Form of Employment Agreement dated as of January 1, 2016 between Executive Vice President/Senior Vice President and Chesapeake Energy Corporation.	8-K	001-13726	10.5	1/6/2016	
10.12†	Form of Indemnity Agreement for officers and directors of Chesapeake Energy Corporation and its subsidiaries.	8-K	001-13726	10.3	6/27/2012	
10.13†	Chesapeake Energy Corporation 2013 Annual Incentive Plan.	DEF 14A	001-13726	Exhibit G	5/3/2013	
10.13.1†	Chesapeake Energy Corporation 2014 Long Term Incentive Plan.	DEF 14A	001-13726	Exhibit F	4/30/2014	
10.13.2†	Form of Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.2	8/6/2014	
10.13.3†	Form of Restricted Stock Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.3	8/6/2014	
10.13.4†	Form of Nonqualified Stock Option Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.4	8/6/2014	
10.13.5†	Form of Performance Share Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.5	8/6/2014	
10.13.6†	Form of Director Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.6	8/6/2014	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X
21	Subsidiaries of Chesapeake Energy Corporation.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of PetroTechnical Services, Division of Schlumberger Technology Corporation.					X
23.3	Consent of Ryder Scott Company, L.P.					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
99.1	Report of PetroTechnical Services, Division of Schlumberger Technology Corporation.	X
99.2	Report of Ryder Scott Company, L.P.	X
101 INS	XBRL Instance Document.	X
101 SCH	XBRL Taxonomy Extension Schema Document.	X
101 CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	X
101 DEF	XBRL Taxonomy Extension Definition Linkbase Document.	X
101 LAB	XBRL Taxonomy Extension Labels Linkbase Document.	X
101 PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	X

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* The Company agrees to furnish supplementally a copy of omitted exhibits and schedules to the Securities and Exchange Commission upon request.

** The Company agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

† Management contract or compensatory plan or arrangement.

Company Information

BOARD OF DIRECTORS

R. Brad Martin [1,2]
Chairman of the Board
Chairman
RBM Venture Company
Former Chairman and
Chief Executive Officer
Saks Incorporated
Memphis, Tennessee

Archie W. Dunham [1,4]
Chairman Emeritus
Former Chairman
ConocoPhillips
Houston, Texas

Vincent J. Intrieri [1,2]
Senior Managing Director
Icahn Capital LP
New York, New York

Robert D. Lawler
President and
Chief Executive Officer
Chesapeake Energy Corporation
Oklahoma City, Oklahoma

John J. "Jack" Lipinski [3,4]
President, Chief Executive Officer
and Director
CVR Energy, Inc.
Sugar Land, Texas

Merrill A. "Pete" Miller, Jr. [4]
Executive Chairman
NOW Inc.
Houston, Texas
Former Executive Chairman
and Chief Executive Officer
National Oilwell Varco, Inc.
Houston, Texas

Frederic M. Poses [1,2]
Chief Executive Officer
Ascend Performance Materials
New York, New York
Will retire from the Board on May 20, 2016, the date of the Annual Meeting

Kimberly K. Querrey [2,3]
President and Managing Member
SQ Advisors, LLC
Naples, Florida

Thomas L. Ryan [2,3]
President and
Chief Executive Officer
Service Corporation International
Houston, Texas

(1) Nominating, Governance and Social Responsibility Committee
(2) Finance Committee
(3) Audit Committee
(4) Compensation Committee

MANAGEMENT TEAM

Robert D. Lawler
President, Chief Executive Officer
and Director

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

M. Christopher Doyle
Executive Vice President –
Operations, Northern Division
Resigned his position on April 6, 2016

Frank J. Patterson
Executive Vice President –
Exploration, Technology & Land

M. Jason Pigott
Executive Vice President –
Operations, Southern Division

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

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

Cathy L. Tompkins
Senior Vice President –
Information Technology and
Chief Information Officer

INVESTOR INFORMATION

Company financial information, public disclosures and other information are available through Chesapeake's website at www.chk.com. We will promptly deliver free of charge, upon request, a copy of the annual report on Form 10-K to any shareholder requesting a copy. Requests should be directed to Investor Relations at our corporate headquarters address.

COMMON STOCK

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange (NYSE) under the symbol CHK. As of March 21, 2016, the record date for our 2016 Annual Meeting of Shareholders, there were approximately 330,000 beneficial owners of our common stock.

INDEPENDENT PUBLIC ACCOUNTANTS

PricewaterhouseCoopers LLP
211 North Robinson Avenue, Suite 1400
Oklahoma City, OK 73102
(405) 290-7200

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to our transfer agent:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021
(800) 884-4225
www.computershare.com

TRUSTEE FOR THE COMPANY'S SENIOR NOTES

Issued prior to 2013
The Bank of New York
Mellon Trust Company, N.A.
101 Barclay Street, 8th Floor
New York, NY 10286
www.bnymellon.com

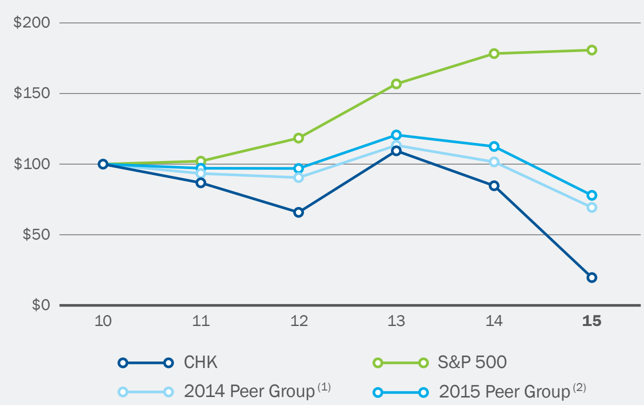
Issued in 2013 – 2015
Deutsche Bank Trust
Company Americas
60 Wall Street, 37th Floor
New York, NY 10005
www.tss.db.com

FORWARD-LOOKING STATEMENTS

The letter to shareholders includes "forward-looking statements" related to our business strategy and objectives for future operations. Although we believe there is a reasonable basis for these forward-looking statements, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2015 Annual Report on Form 10-K included in this report. We caution you not to place undue reliance on forward-looking statements, and we undertake no obligation to update this information, except as required by law. We urge you to carefully review and consider the disclosures made in our Form 10-K and our other filings with the Securities and Exchange Commission regarding the risks and factors that may affect our business.

CHESAPEAKE'S FIVE-YEAR COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on December 31, 2010 and the reinvestment of all dividends. Source: Zacks Investment Research, Inc.



(1) The 2014 peer group is comprised of Anadarko Petroleum Corporation, Apache Corporation, Continental Resources, Inc., Devon Energy Corporation, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc. and Occidental Petroleum Corporation.

(2) The 2015 peer group is comprised of Anadarko Petroleum Corporation, Apache Corporation, ConocoPhillips, Devon Energy Corporation, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc. and Occidental Petroleum Corporation. The change in the companies in our peer group was designed to more accurately show the returns of companies that are more similar to Chesapeake in scope and nature of business operations.

6100 NORTH WESTERN AVENUE
OKLAHOMA CITY, OK 73118

CHK.COM

CHESAPEAKE