LEADERSHIP
PERFORMANCE
VALUE

CHESAPEAKE ENERGY CORPORATION | 2014 ANNUAL REPORT

At Chesapeake, our people are focused on performance. From elevating innovative solutions to demonstrating operational and financial leadership as well as capital efficiency, our employees are creating lasting value for our shareholders every day.

Our core values are the foundation for every decision we make. We are committed to conducting ourselves and our business with:

INTEGRITY AND TRUST

RESPECT

TRANSPARENCY AND OPEN COMMUNICATION

COMMERCIAL FOCUS

CHANGE LEADERSHIP

DEAR FELLOW SHAREHOLDERS

In 2014 we transformed every aspect of our business to build a new foundation — one based on financial discipline and profitable and efficient growth from our resources. During this critical year, our employees delivered exceptional results while significantly improving our financial position. We achieved the best safety performance in company history and further improved capital efficiencies in our major operating areas. From a financial perspective, we became significantly stronger, less complex and much more flexible. These along with many other achievements drove Chesapeake to greater stability and strength.

GENERATING VALUE

We grew our total oil and natural gas equivalent production by 9% in 2014, adjusting for divestitures, while reducing our total capital expenditures by approximately 14% compared to 2013. We also reached a production record of 770,000 barrels of oil equivalent (boe) per day in mid-December. More importantly, we drove billions of dollars in value into our company through numerous efficiencies, continuous improvement and cost leadership.

In 2014 we reduced drilling and completions capital expenditures by 18% to $4.5 billion, saving $1 billion compared to 2013. Our 2014 operating cash flow was approximately $5 billion, reflecting the lowest funding gap in 10 years. In addition, combined production and general and administrative costs per boe dropped 10% to a nine-year low.

GAINING FINANCIAL FLEXIBILITY

Chesapeake became dramatically stronger, less complex and much more flexible in 2014 as three major accomplishments set us apart from our peers. We completed one of the largest and most significant transactions in company history with the divestiture of certain assets in the southern Marcellus and eastern Utica shales. Receiving approximately $5 billion for the assets during a depressed commodity price environment — assets which represented only 8% of proved reserves — gives us tremendous financial flexibility. We also completed a $450 million acquisition and exchange that doubled our working interest in the oil-rich Powder River Basin. Finally, we successfully spun off our oilfield services division into the public company Seventy Seven Energy Inc.

We reached another first in company history with a new unsecured $4 billion credit facility with investment grade-like terms. Moody's and S&P each upgraded Chesapeake by two notches, placing us one level below investment grade at both rating agencies. Since 2012 we have reduced total leverage by $5.5 billion.

OPERATING RESPONSIBLY

The safety of our employees, contractors, the environment and the public is our number one priority, and our 2014 performance in those areas was outstanding. We ended the year with the lowest total recordable incident rate in company history and reduced our cumulative reportable spill volume by 42%.

We remain focused on our responsibility to stakeholders, and in 2014 that included a renewed commitment to our landowners. We initiated face-to-face meetings in our two largest producing regions, Pennsylvania and Texas, and continue to initiate communications with many of our landowners. In 2014 we also invested in our employees through career development programs, introduced a competitively based companywide employee compensation program that aligned with our corporate performance goals and fostered a culture of continuous learning and elevating innovative solutions.

DEMONSTRATING E&P LEADERSHIP

Our record accomplishments have positioned us to remain strong and flexible in 2015. We continue to respond decisively to the lower commodity price environment, including a reduced capital budget and activity level. However, we will not shift our focus from driving differential performance, ensuring every dollar we invest creates value, increases our financial and operational flexibility and lowers our business costs. These strategies will allow us to continue the historic transformation of our company into a leader in the E&P industry. We have made impressive progress, yet there is so much more we will accomplish. Thank you for investing in Chesapeake Energy.

Robert D. Lawler
President, Chief Executive Officer and Director
April 10, 2015

KEY ACCOMPLISHMENTS

Generated ~$5 billion in cash from one of our largest asset sales in company history

Doubled our working interest in the oil-rich Powder River Basin

Improved capital efficiency 40 – 65% across major operating areas since 2012

Continued our commitment to safety with a 35% improvement in our total recordable incident rate — a company record

Entered into an unsecured credit facility of $4 billion — a company first

BUSINESS STRATEGIES

We are focused on creating long-term shareholder value, improving capital efficiencies and driving top performance.

FINANCIAL DISCIPLINE

- Balance capital expenditures with cash flow from operations
- Increase financial and operational flexibility through value-driven spending and lower business costs
- Achieve investment grade metrics

PROFITABLE AND EFFICIENT GROWTH FROM CAPTURED RESOURCES

- Develop world-class inventory
- Target top-quartile operating and financial metrics
- Pursue continuous improvement
- Drive value leakage out of our operations

EXPLORATION

- Leverage innovative technology and expertise
- Explore and exploit domestic resources
- Pursue international growth opportunities

BUSINESS DEVELOPMENT

- Target strategic acquisitions
- Enhance and expand the portfolio

FINANCIAL REVIEW

FINANCIAL AND OPERATING DATA

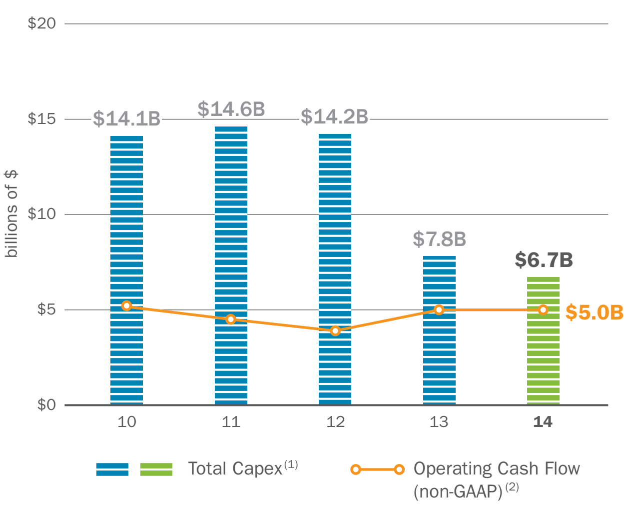
($ in millions, except per share data)

Years Ended December 31	2014	2013	2012	2011	2010
Revenues:					
Oil, natural gas and NGL	$ 8,180	$ 7,052	$ 6,278	$ 6,024	$ 5,647
Marketing, gathering and compression	12,225	9,559	5,431	5,090	3,479
Oilfield services	546	895	607	521	240
Total revenues	$ 20,951	$ 17,506	$ 12,316	$ 11,635	$ 9,366
Total operating expenses	$ 17,474	$ 15,437	$ 14,010	$ 8,714	$ 6,561
Total other income (expense)	$ (277)	$ (627)	$ 720	$ (41)	$ 79
Income (loss) before income taxes	$ 3,200	$ 1,442	$ (974)	$ 2,880	$ 2,884
Income tax expense (benefit)	$ 1,144	$ 548	$ (380)	$ 1,123	$ 1,110
Net income (loss) attributable to Chesapeake	$ 1,917	$ 724	$ (769)	$ 1,742	$ 1,774
Net income (loss) available to common stockholders	$ 1,273	$ 474	$ (940)	$ 1,570	$ 1,663
EPS – diluted	$ 1.87	$ 0.73	$ (1.46)	$ 2.32	$ 2.51
Operating cash flow (non-GAAP)[(a)]	$ 5,026	$ 4,958	$ 3,920	$ 4,487	$ 5,169
OTHER OPERATING AND FINANCIAL DATA					
Proved reserves in oil equivalents (mmboe)	2,469	2,678	2,615	3,132	2,849
Future net oil and natural gas revenues discounted at 10% (PV-10)[(b)]	$ 22,012	$ 21,676	$ 17,773	$ 19,878	$ 15,146
Production (mmboe)	258	244	237	199	173
Stock price (at end of period – split adjusted)	$ 19.47	$ 27.14	$ 16.62	$ 22.29	$ 25.91

(a) A non-GAAP financial measure. Please refer to the Investors section of our website at www.chk.com for reconciliations of non-GAAP financial measures to comparable financial measures calculated in accordance with generally accepted accounting principles.

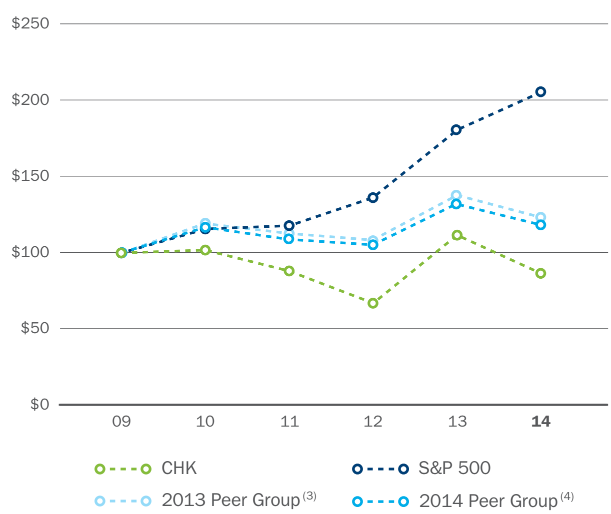
(b) PV-10 is the present value (10% discount rate) of estimated future gross revenues to be generated from the production of proved reserves, net of production and future development costs, using assumed prices and costs.

TOTAL CAPEX AND OPERATING CASH FLOW



CHESAPEAKE'S FIVE-YEAR COMMON STOCK PERFORMANCE

The graph assumes an investment of $100 on December 31, 2009 and the reinvestment of all dividends. Source: Zacks Investment Research, Inc.



(1) Includes capital expenditures for drilling and completions, property acquisitions, geological and geophysical costs, property, plant and equipment, investments and capitalized interest.

(2) A non-GAAP financial measure. Please refer to the Investors section of our website at www.chk.com for reconciliations of non-GAAP financial measures to comparable financial measures calculated in accordance with generally accepted accounting principles.

(3) The 2013 peer group is comprised of Anadarko Petroleum Corporation, Apache Corporation, Continental Resources, Inc., Devon Energy Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Noble Energy, Inc., Occidental Petroleum Corporation, SandRidge Energy and Southwestern Energy.

(4) 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. 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 size, scope and nature of business operations.

2014 was a foundational year for Chesapeake, with record achievements across the company. CEO Doug Lawler discusses the significance of these key accomplishments.

Q: Why was the southern Marcellus and eastern Utica divestiture such an important step for Chesapeake?

A: This was one of the largest and most significant transactions in company history. It provided us with approximately $5 billion in cash and substantial flexibility for the future. At the time, the divested assets comprised just 8% of total proved reserves, and the proceeds equaled 40% of Chesapeake's market capitalization, further demonstrating the strength of our industry-leading, high-quality portfolio.

Q: How will the additional working interest in the Powder River Basin benefit operations?

A: Our acquisition of RKI's acreage in the Powder River Basin's southern portion consolidated our position, doubled our working interest and immediately added net incremental production of approximately 4,500 boe per day. In addition to increasing the Niobrara oil potential, the transaction offered incremental access to five stacked oil pay zones, or Upper Cretaceous formations, which increased our potentially recoverable gross resources to more than 2 billion boe in Wyoming's Powder River Basin.

Q: What was the significance of achieving the $4 billion unsecured credit facility in December?

A: For the first time in company history, Chesapeake entered into an unsecured credit facility with investment grade-like terms. Previously, we had to provide proved reserves as security, which tied up assets, added complexity to our business and involved rigid, inflexible terms. Closing on this type of facility could not have happened without our employees' outstanding commitment to financial discipline, which resulted in a dramatically improved balance sheet by the end of 2014. Combined with the proceeds from our southern Marcellus and eastern Utica divestiture and our $5.5 billion reduction in leverage since 2012, the new credit facility provides us with a significant amount of liquidity and flexibility.

Q: What has the spin-off of Seventy Seven Energy allowed Chesapeake to accomplish?

A: Spinning off Seventy Seven Energy into its own company allowed us to focus our resources on our core E&P operations, support our business strategy of reducing leverage and complexity, and unlock shareholder value that was tied to our oilfield services business. Since the spin-off, Chesapeake has become a much more efficient and less complex organization.

One of our most significant asset sales in company history provided us with ~$5 billion in cash and substantial flexibility for the future.

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, 2014
[ ] 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 [X] NO [ ]

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

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

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

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

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2014 was approximately $20.5 billion. As of February 9, 2015, there were 665,038,368 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2015 Annual Meeting of Shareholders are incorporated by reference in Part III.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
2014 ANNUAL REPORT ON FORM 10-K
TABLE OF CONTENTS

PART I

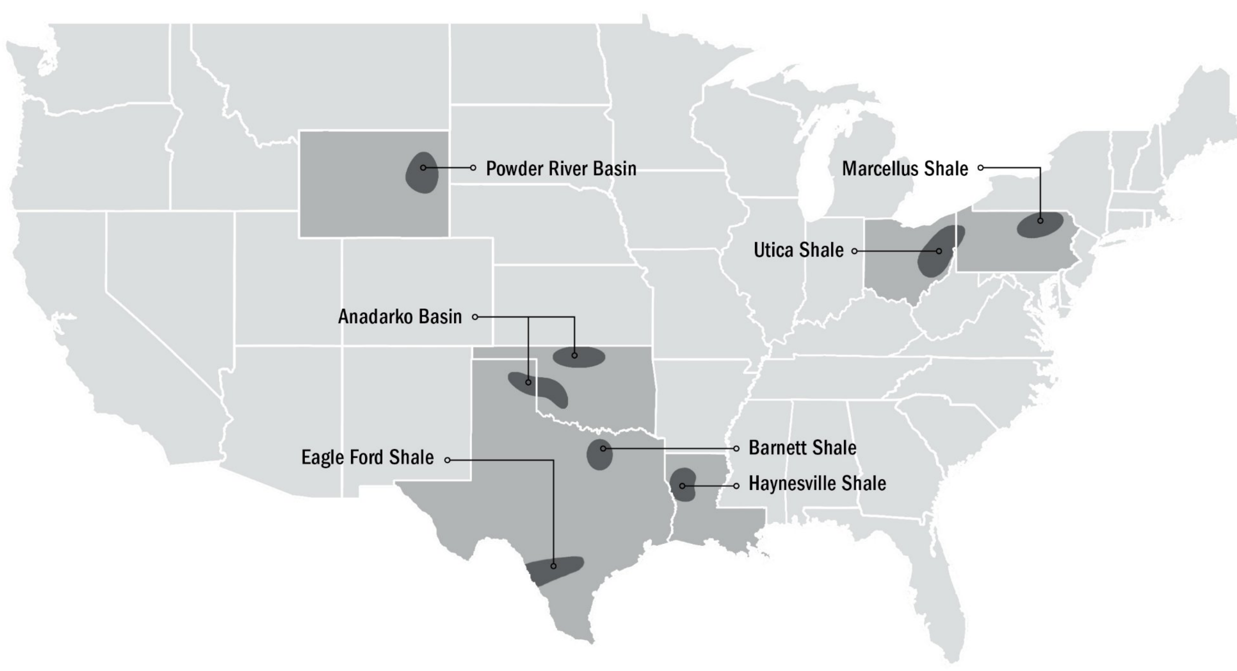
Item 1. *Business*

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 20.

Our Business

Chesapeake is currently the second-largest producer of natural gas and the 11th largest producer of oil and natural gas liquids (NGL) in the United States. We own interests in approximately 45,100 oil and natural gas wells that produced an average of approximately 729 mboe per day in the 2014 fourth quarter, net to our interest. We have a large and geographically diverse resource base of onshore U.S. unconventional liquids and natural gas 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 Granite Wash, Cleveland, Tonkawa and Mississippian Lime plays in the Anadarko Basin in northwestern Oklahoma and the Texas Panhandle; and the Niobrara Shale and Upper Cretaceous sands 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 map below illustrates the locations of Chesapeake's oil and natural gas exploration and production operations.



The Company's estimated proved reserves as of December 31, 2014 were 2.469 bboe, a decrease of 209 mmboe, or 8%, from 2.678 bboe as of December 31, 2013. The 2014 proved reserve movement included 448 mmboe of extensions and discoveries, 27 mmboe of upward revisions resulting primarily from higher average natural gas prices and 78 mmboe of downward 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 2014, we produced 258 mmboe, acquired 14 mmboe and divested 362 mmboe of estimated proved reserves, primarily through the sale of our southern Marcellus and a portion of our eastern Utica Shale assets. Before price differential adjustments, oil prices used in estimating proved reserves decreased and natural gas prices used in estimating proved reserves increased as of December 31, 2014 compared to December 31, 2013 using the trailing 12-month average prices required by the Securities and Exchange Commission (SEC). Oil prices decreased by $1.84 per bbl, or 2%, to $94.98 per bbl from $96.82 per bbl. Natural gas prices increased $0.68

per mcf, or 19%, to $4.35 per mcf from $3.67 per mcf. Proved developed reserves represented 75% of our proved reserves as of December 31, 2014 compared to 68% as of December 31, 2013.

Our daily production for 2014 averaged 706 mboe, an increase of 36 mboe, or 5%, over the 670 mboe of daily production for 2013, and consisted of approximately 115,800 bbls of oil (16% on an oil equivalent basis), approximately 90,500 bbls of NGL (13% on an oil equivalent basis), and approximately 3.0 bcf of natural gas (71% on an oil equivalent basis). Our average daily oil production increased 3%, or approximately 3 mbbls per day; our average daily natural gas production remained the same; and our average daily NGL production increased 58%, or approximately 33 mbbls per day over the average daily production for 2013.

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

With substantial leasehold positions in most of the premier U.S. onshore resource plays, Chesapeake is focused on finding and producing hydrocarbons in a responsible and efficient manner that seeks to maximize shareholder returns. We are committed to increasing our profitability and decreasing our financial complexity through the execution of our business strategy, which consists of four fundamental tenets: financial discipline, profitable and efficient growth from captured resources, exploration and business development.

We are applying financial discipline to all aspects of our business, with the primary goals of balancing capital expenditures with cash flow from operations, increasing financial and operational flexibility through value-driven spending and lower business costs and achieving investment grade metrics. As a result of our focus on financial discipline, our combined production and general and administrative expenses decreased to $5.94 per boe in 2014 compared to $6.60 per boe in 2013.

The Company's substantial inventory of hydrocarbon resources, including our acreage inventory, provides a strong foundation for future growth. We believe that focusing on profitable and efficient growth from our captured resources will allow us to deliver attractive financial returns through all phases of the commodity price cycle. We have seen and continue to see increased efficiencies through our leveraging of first-well investments made in prior periods, including drilling on pre-existing pads. We have a competitive capital allocation process designed to optimize our asset portfolio and identify the highest quality projects for future investment. To better understand our opportunities for continuous improvement, we benchmark our performance against that of our peers and evaluate the performance of completed projects. We also pay careful attention to safety, regulatory compliance and environmental stewardship measures while executing our strategy.

Although the Company's substantial inventory of hydrocarbon resources provides a strong foundation, we believe exploration and business development are also key opportunities for future growth. We believe we will have opportunities to enhance or expand our portfolio through leveraging our innovative technology and expertise, exploring and exploiting new domestic resources, pursuing international growth opportunities and targeting strategic acquisitions. We believe these platforms will increase shareholder returns.

During 2014, we executed on our business strategy by:

- selling noncore assets in the southern Marcellus and Utica Shale plays in December 2014, which provided approximately 7% of our total 2014 production, for net proceeds of approximately $5.0 billion;
- completing additional dispositions of other noncore assets for aggregate net proceeds of approximately $1.8 billion;
- acquiring approximately 203,000 net acres and 186 gross wells in the southern Powder River Basin of Wyoming;
- completing the spin-off of our oilfield services business into Seventy Seven Energy Inc. (NYSE:SSE), a stand-alone publicly traded company;
- reducing financial complexity through a variety of transactions;
- entering into a new unsecured $4.0 billion credit facility with investment grade-like terms;
- ending the year with approximately $4.0 billion in cash and no borrowings under our revolving credit facility; and
- achieving record production of approximately 770,000 boe per day in mid-December 2014 with fewer than half the rigs used in 2012.

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 Granite Wash, Cleveland, Tonkawa and Mississippian Lime plays in 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 and Upper Cretaceous sands in the Powder River Basin in Wyoming.

Well Data

As of December 31, 2014, we held an interest in approximately 45,100 gross (18,500 net) productive wells, including 33,600 properties in which we held a working interest and 11,500 properties in which we held an overriding royalty interest. Of the wells in which we had a working interest, 28,000 gross (15,900 net) were classified as natural gas productive wells and 5,600 gross (2,600 net) were classified as oil productive wells. Chesapeake operated approximately 21,000 of its 33,600 productive wells in which we had a working interest. During 2014, we completed 1,048 gross (625 net) wells and participated in another 892 gross (57 net) wells completed by other operators. We operate approximately 90% 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.

	2014				2013				2012			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	1,784	99	629	99	1,704	99	847	99	2,075	99	956	99
Dry	3	1	1	1	21	1	9	1	21	1	5	1
Total	1,787	100	630	100	1,725	100	856	100	2,096	100	961	100
Exploratory:												
Productive	145	95	46	88	209	97	124	96	495	98	305	98
Dry	8	5	6	12	6	3	5	4	10	2	6	2
Total	153	100	52	100	215	100	129	100	505	100	311	100

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

	2014		2013		2012	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Southern	1,448	473	1,352	698	1,933	982
Northern	492	209	588	287	668	290
Total	1,940	682	1,940	985	2,601	1,272

At December 31, 2014, we had 898 gross (464 net) wells in drilling or completing status.

Production, Sales, Prices and Expenses

The following table sets forth 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:

	December 31,		
	2014	**2013**	**2012**
Net Production:			
Oil (mmbbl)	42	41	31
Natural gas (bcf)	1,095	1,095	1,129
NGL (mmbbl)	33	21	18
Oil equivalent (mmboe)[a]	258	244	237
Oil, Natural Gas and NGL Sales ($ in millions):			
Oil sales	$ 3,682	$ 3,911	$ 2,829
Oil derivatives - realized gains (losses)[b]	(185)	(108)	39
Oil derivatives - unrealized gains (losses)[b]	859	280	857
Total oil sales	4,356	4,083	3,725
Natural gas sales	2,777	2,430	2,004
Natural gas derivatives - realized gains (losses)[b]	(191)	9	328
Natural gas derivatives - unrealized gains (losses)[b]	535	(52)	(331)
Total natural gas sales	3,121	2,387	2,001
NGL sales	703	582	526
NGL derivatives - realized gains (losses)[b]	—	—	(9)
NGL derivatives - unrealized gains (losses)[b]	—	—	35
Total NGL sales	703	582	552
Total oil, natural gas and NGL sales	$ 8,180	$ 7,052	$ 6,278
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 87.13	$ 95.17	$ 90.49
Natural gas ($ per mcf)	$ 2.54	$ 2.22	$ 1.77
NGL ($ per bbl)	$ 21.27	$ 27.87	$ 29.89
Oil equivalent ($ per boe)	$ 27.78	$ 28.33	$ 22.61
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 82.76	$ 92.53	$ 91.74
Natural gas ($ per mcf)	$ 2.36	$ 2.23	$ 2.07
NGL ($ per bbl)	$ 21.27	$ 27.87	$ 29.37
Oil equivalent ($ per boe)	$ 26.32	$ 27.92	$ 24.12
Other Operating Income[c] ($ in millions):			
Marketing, gathering and compression net margin	$ (11)	$ 98	$ 119
Oilfield services net margin	$ 115	$ 159	$ 142
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 4.69	$ 4.74	$ 5.50
Production taxes	$ 0.90	$ 0.94	$ 0.79
General and administrative expenses[d]	$ 1.25	$ 1.86	$ 2.26
Oil, natural gas and NGL depreciation, depletion and amortization	$ 10.41	$ 10.59	$ 10.58
Depreciation and amortization of other assets	$ 0.90	$ 1.28	$ 1.28
Interest expense[e]	$ 0.63	$ 0.65	$ 0.35

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

(b) Realized gains and 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 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.

(c) Includes revenue and operating costs. See *Results of Operations - Depreciation and Amortization of Other Assets* in Item 7 of Part II of this report for details of the depreciation and amortization associated with our marketing, gathering and compression and former oilfield services operating segments.

(d) Includes stock-based compensation and excludes restructuring and other termination costs.

(e) 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.

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2014 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 oil and natural gas reserves are located within the United States.

	December 31, 2014			
	Oil	Natural Gas	NGL	Total
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)
Proved developed	229	8,615	198	1,864
Proved undeveloped	192	2,077	68	605
Total proved[a]	421	10,692	266	2,469

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[b]	$ 33,591	$ 13,534	$ 47,125
Present value of estimated future net revenue[b]	$ 17,024	$ 4,988	$ 22,012
Standardized measure[b][c]			$ 17,133

Operating Division	Oil	Natural Gas	NGL	Oil Equivalent	Percent of Proved Reserves	Present Value
	(mmbbl)	(bcf)	(mmbbl)	(mmboe)		($ millions)
Southern	372	6,882	182	1,701	69%	$ 15,372
Northern	49	3,810	84	768	31%	6,640
Total	421	10,692	266	2,469	100%	$ 22,012 [b]

(a) Includes 2 mmbbl of oil, 46 bcf of natural gas and 5 mmbbl of NGL reserves owned by the Chesapeake Granite Wash Trust, 1 mmbbl of oil, 22 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, 2014. For the purpose of determining "prices", we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended

December 31, 2014. The prices used in our reserve reports were $94.98 per bbl of oil and $4.35 per mcf of natural gas, before price differential adjustments. Including the effect of price differential adjustments, the prices used in our reserve reports were $89.09 per bbl of oil, $2.68 per mcf of natural gas and $24.10 per bbl of NGL. 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, 2014. 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 ($4.9 billion as of December 31, 2014).

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, 2014, our reserve estimates included 605 mmboe of reserves classified as proved undeveloped, compared to 869 mmboe as of December 31, 2013. Presented below is a summary of changes in our proved undeveloped reserves (PUDs) for 2014.

	Total
	(mmboe)
Proved undeveloped reserves, beginning of period	869
Extensions, discoveries and other additions	227
Revisions of previous estimates	(162)
Developed	(225)
Sale of reserves-in-place	(105)
Purchase of reserves-in-place	1
Proved undeveloped reserves, end of period	605

As of December 31, 2014, there were no PUDs that had remained undeveloped for five years or more. In 2014, we invested approximately $1.289 billion, net of drilling and completion cost carries of $73 million, to convert 225 mmboe of PUDs to proved developed reserves. In 2015, we estimate that we will invest approximately $1.7 billion, net of drilling and completion cost carries of $11 million, for PUD conversion. The downward revisions of 162 mmboe of PUDs in 2014 were primarily related to the removal of PUDs in the Marcellus Shale, the Eagle Ford Shale and the Anadarko Basin.

The future net revenue attributable to our estimated proved undeveloped reserves of $13.5 billion as of December 31, 2014, and the $5 billion present value thereof, have been calculated assuming that we will expend approximately $6.3 billion to develop these reserves ($1.7 billion in 2015, $1.5 billion in 2016, $1.6 billion in 2017, $1.2 billion in 2018 and $292 million in 2019), 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.

The SEC's rules for reporting reserves allow the booking of proved undeveloped reserves at locations other than direct offsets to producing wells. All proved reserves are required to meet reasonable certainty standards; thus, locations that are not direct offsets to producing wells must be underlain by the productive formation. Reasonable certainty also requires that the formation is continuous between the producing wells and the PUD locations and that the PUDs are economically viable.

Our proved reserves as of December 31, 2014 included PUDs more than directly offsetting producing wells in three resource plays: the Haynesville Shale, the Marcellus Shale and the Eagle Ford Shale. In all other areas, we restricted PUD locations to immediate offsets to producing wells. Within the Haynesville, Marcellus and Eagle Ford Shale plays, we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (collected both vertically and horizontally) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores; whole cores; and data measured in our internal core analysis facility. After the geologic areas were shown to be continuous, statistical analysis of existing producing wells was conducted to generate an area of reasonable certainty at distances from established production. Undrilled locations within these proved areas qualify as PUDs; however, due to other factors and SEC reserves guidance, numerous locations within these three statistically evaluated plays have not yet been booked as PUDs.

Our annual net decline rate on producing properties is projected to be 30% from 2015 to 2016, 20% from 2016 to 2017, 15% from 2017 to 2018, 13% from 2018 to 2019 and 11% from 2019 to 2020. Of our 1,864 mmboe of proved developed reserves as of December 31, 2014, approximately 156 mmboe, or 8%, were non-producing.

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue were determined after giving effect to the assumed maximum participation by other parties to our farm-out and participation agreements. The prices used in calculating the estimated future net revenue attributable to proved reserves do not reflect market prices for oil and natural gas production sold subsequent to December 31, 2014. The estimated proved reserves may not be produced and sold at the assumed prices.

The Company's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves as of December 31, 2014, 2013 and 2012, along with the changes in quantities and standardized measure of these 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 21% of the proved reserves estimates (by volume) 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:

- 24 years of practical experience working for major oil companies, including 16 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, including, with respect to our engineers, a minimum of an undergraduate degree in petroleum, mechanical or chemical engineering or other applicable technical discipline. With respect to our engineering technicians, a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field is required. 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 determine and report proved reserves. Reserves estimates are made by experienced reservoir engineers or under their direct supervision.
- The Corporate Reserves Department reviews all of 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 Vice President 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.

We engaged two third-party engineering firms to prepare approximately 79% of our estimated proved reserves (by volume) at year-end 2014. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2014 is presented below.

	% Prepared (by Volume)	Operating Division
Ryder Scott Company, L.P.	54%	Southern
PetroTechnical Services, Division of Schlumberger Technology Corporation	25%	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,		
	2014	2013	2012
		($ in millions)	
Acquisition of Properties:			
Proved properties	$ 214	$ 22	$ 332
Unproved properties	1,224	997	2,981
Exploratory costs	421	699	2,353
Development costs	4,204	4,888	6,733
Costs incurred[(a)(b)]	$ 6,063	$ 6,606	$ 12,399

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $679 million, $884 million and $784 million in 2014, 2013 and 2012, respectively.

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

Capitalized interest	$ 604	$ 815	$ 976
Asset retirement obligations	$ 39	$ 7	$ 32

A summary of our exploration and development, acquisition and divestiture activities in 2014 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	1,448	473	$ 3,180	$ 182	$ —	$ (199)	$ (289)	$ 2,874
Northern	492	209	1,445	1,042	214	(902)	(4,461)	(2,662)
Total	1,940	682	$ 4,625	$ 1,224	$ 214	$ (1,101)	$ (4,750)	$ 212

(a) Includes capitalized internal costs of $230 million and related capitalized interest of $604 million.

Acreage

The following table sets forth, as of December 31, 2014, our gross and net developed and undeveloped oil and natural gas leasehold and fee mineral acreage. "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	6,095	2,996	2,103	1,068	154	28	8,352	4,092
Northern	1,840	1,381	5,844	3,646	687	437	8,371	5,464
Total	7,935	4,377	7,947	4,714	841	465	16,723	9,556

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, 2014 the expiration periods of gross and net undeveloped leasehold acres.

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2015	1,820	1,058
2016	1,703	1,105
2017	1,083	722
After 2017	3,341	1,829
Total[(a)]	7,947	4,714

(a) Includes 1.873 million gross (976,000 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 ExxonMobil Corporation and Plains Marketing, L.P. constituted approximately 12% and 11%, respectively, of our total revenues (before the effects of hedging) for the years ended December 31, 2014 and 2012, respectively. 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 provided services to joint working interest owners and other third-party customers. We generated revenues from our gathering, treating and compression activities through various gathering rate structures. We also processed a portion of our natural gas at various third-party plants.

In 2013 and 2012, we sold substantially all of our midstream business, including most of our gathering assets. We continue to own the following midstream assets: (i) certain gathering pipelines primarily associated with vertical well production in the northeastern United States; and (ii) 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. Once the compressors are complete, a majority of the completed compressors are sold to MidCon. MidCon operates wellhead and system compressors, with approximately 500,000 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.

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. Further, in 2012, seven states sued the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and gas sources are appropriate and, if so, to promulgate performance standards for methane emissions from existing oil and gas sources. In April 2014, the EPA released a set of five white papers analyzing methane emissions from the industry and, based on responses received, announced in January 2015 that it plans to issue a rule governing methane emissions from oil and gas sources in the summer of 2015. The Bureau of Land Management (BLM) is also expected to address methane emissions from oil and gas sources on federal lands in the summer of 2015.

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 addition, in December 2014, the EPA published its proposal to revise downward the ozone national ambient air quality standard to 65-70 parts per billion. A final rule is expected in 2015. We cannot predict the actions that these regulations will require or prohibit, but 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 April 2014, the EPA and USACE jointly proposed guidance regarding the definition of waters of the United States that substantially expands the waters regulated under the CWA. 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. 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.

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 December 2014, the governor of New York announced his intention to create a statewide ban on hydraulic fracturing, replacing the current moratorium. 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 final draft report expected to be released for public comment and peer review in early 2015. In addition, the BLM published a revised draft of proposed rules in July 2013 that would impose new requirements on hydraulic fracturing operations conducted on federal and tribal lands. It is expected that this rule will become final in early 2015 and will focus on chemical disclosure, wellbore integrity and water management. 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.

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.*

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. The EPA announced it will propose 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 $75 million control of well policy 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, 48, 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., 38, 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, 42, 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.

Douglas J. Jacobson, ***Executive Vice President - Acquisitions and Divestitures***

Douglas J. Jacobson, 61, has served as Executive Vice President - Acquisitions and Divestitures since 2006. He served as Senior Vice President - Acquisitions and Divestitures from 1999 to 2006.

John M. Kapchinske, ***Executive Vice President - Exploration & Subsurface Technology***

John M. Kapchinske, 64, has served as Executive Vice President - Exploration & Subsurface Technology since January 2015 and previously served as Senior Vice President - Exploration & Subsurface Technology since August 2013. Prior to then, he served as Senior Vice President - Geoscience from May 2011 to August 2013. He served as Vice President - Geoscience from 2005 to May 2011 and Geoscience Manager from 2001 to 2004.

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

Mikell J. ("Jason") Pigott, 41, 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, 47, 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, 49, 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, 54, 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 5,500 employees as of December 31, 2014 compared to approximately 10,800 employees as of December 31, 2013. As a result of the spin-off of our oilfield services business in June 2014, we experienced a reduction of approximately 5,100 employees.

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.

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 major expenditure 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 a 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***

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

Our revenues, operating results, profitability and ability to grow depend primarily upon the prices we receive for our share of the oil, natural gas and NGL we sell. We require substantial expenditures to replace reserves, sustain production and fund our business plans. Lower oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures 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 and reserves. In addition, lower 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 and natural gas, 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;
- potential 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; 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 declined significantly in the second half of 2014 and have remained low compared to prices in the first half of 2014. Even with oil and natural gas derivatives currently in place to mitigate price risks associated with our future production (43% of our forecasted 2015 oil production and 43% of our forecasted 2015 natural gas production through swaps and three-way collars), our 2015 revenue and results of operations will be adversely affected if commodity prices remain at current levels. Further, a prolonged extension of prices at these levels will reduce the quantities of reserves that may be economically produced and will require us to impair the carrying value of our oil and natural gas assets in 2015.

We expect to write down the carrying value of our oil and natural gas properties in 2015 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, in 2012, we reported a non-cash impairment charge on our oil and natural gas properties of $3.315 billion, primarily resulting from a 10% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of September 30, 2012, as compared to June 30, 2012, and the impairment of certain undeveloped leasehold interests. In the second half of 2014, the NYMEX West Texas Intermediate (WTI) index price of oil declined significantly from $105.37 per bbl as of June 30, 2014 to $53.27 per bbl as of December 31, 2014, and the Henry Hub index price of natural gas declined from $4.46 per mcf to $2.89 per mcf over the same period. Oil prices have declined further in 2015. The NYMEX WTI index price of oil on February 20, 2015 was $50.34 per bbl, and the Henry Hub index price of natural gas was $2.95 per mcf. Based on the first-day-of the-month prices we have received over the 11 months ended February 2015, we expect to have a material write-down in the carrying value of our oil and natural gas properties in the first quarter of 2015. 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.

Our exploration, development and acquisition activities require substantial capital expenditures. We intend to fund our capital expenditures through cash flows from operations and to the extent that is not sufficient, cash on hand and borrowings under our revolving credit facility. Our ability to generate operating cash flow is subject to 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 production operations, 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. In addition, approximately 25% of our total estimated proved reserves (by volume) as of December 31, 2014 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates at December 31, 2014 reflect an expected decline in the production rate on our producing properties of approximately 30% in 2015 and 20% in 2016. 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 differ from our estimates.

This Form 10-K contains estimates of our proved reserves and the estimated future net revenues from our proved reserves. These estimates 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, 2014, approximately 25% 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 $6.3 billion during the five years ending in 2019. 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 the associated volumes 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, 2014 present value is based on $94.98 per bbl of oil and $4.35 per mcf of natural gas before price differential adjustments. These prices are substantially higher than current and expected 2015 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 by oil, natural gas and NGL purchasers 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. The effective interest rate at various times and the risks associated with our business or the oil and natural 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 acquired significant amounts 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 a decline in commodity prices, among others. The profitability of wells, particularly in certain of the shale plays in which we operate, may 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. 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 expire and we are unable to renew the leases, we will lose our right to develop the related properties. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties.

Our commodity price risk management activities may 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, including instances in which our production is less than expected.

Derivative transactions involve the risk that counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. During periods of declining commodity prices, such as the second half of 2014 and continuing into 2015, our commodity price derivative asset positions increase, which increases our counterparty exposure. Although the counterparties to our multi-counterparty secured hedging facility 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 subject to commodity price changes.

Most of our oil and natural gas derivative contracts are with the 17 counterparties to our multi-counterparty hedging facility. Our obligations under the facility are secured by oil and natural gas proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times. Under certain circumstances, such as a spike in volatility measures without a corresponding change in commodity prices, or a decline in commodity prices, the collateral value could fall below the coverage designated, and we would be required to post additional reserve collateral to our hedging facility. If we did not have sufficient unencumbered oil and natural gas properties available to cover the shortfall, we would be required to post cash or letters of credit with the counterparties. 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 expect to be obligated to make a substantial additional payment with regard to the redemption at par on May 13, 2013 of our 6.775% Senior Notes due 2019 (2019 Notes). We proceeded with the redemption in reliance on a judgment of the U.S. District Court for the Southern District of New York declaring that the redemption notice we issued was timely and effective for a redemption at par pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes. In November 2014, however, the U.S. Court of Appeals for the Second Circuit reversed the District Court's declaratory judgment and held that the notice was not effective to redeem the 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. We accrued a loss contingency of $100 million and estimate the range of potential loss between $100 million and $380 million, plus prejudgment interest of up to 9%. The high end of this range is based upon the indenture trustee's request in mid-February 2015 that the Court order us to pay noteholders the "make-whole" amount (as defined in the indenture) less the par amount already paid. Our $100 million accrual is based on an estimate of the remedy required to restore the redeemed noteholders and the Company to the economic positions they would have been in had the 2019 Notes not been redeemed.

The Company is 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. We have agreed to settle, subject to court approval, with a putative class of Oklahoma royalty owners for 2004-2014 claims for $119 million. An agreed-upon settlement with Pennsylvania royalty owners for approximately $12 million is also subject to court approval. Numerous other cases, primarily in Texas, 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, and we are defending shareholder derivative claims against current and former directors and officers. The outcome of any pending 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 2015 and future years. Further, attention to these matters by members of our senior management has been required, reducing the time they have available to devote to managing the Company's business.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2014, we had indebtedness of $11.535 billion, and our net indebtedness represented 30% of our total book capitalization, which we define as the sum of total equity and total current and long-term debt less unrestricted cash.

Our level of indebtedness affects our operations in several ways, including the following:

- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional financing we may need in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants; and
- a lowering of the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate we pay on our revolving credit facility and may subject us to additional covenants under that facility.

Our revolving credit facility is unsecured. However, we will be required to provide collateral and the revolving credit facility will become subject to a borrowing base if our credit rating declines to specified levels. In addition, the institution of a borrowing base or, following any such institution, the reduction of the borrowing base due to a decline in commodity prices or otherwise, could require us to repay indebtedness in excess of the borrowing base, or we might need to further secure the lenders with additional collateral. A prolonged decline in commodity prices could increase the risk of a lower credit rating. We may incur additional debt, including secured indebtedness, in order to develop our properties and make future acquisitions. A higher level of indebtedness increases the risk that we may default on our obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. In addition, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default and acceleration of such indebtedness and lead to cross defaults under our other indebtedness. In this circumstance, our ability to refinance indebtedness may be limited.

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

We may take actions in response to the current market environment and as part of our strategic priorities to reduce financial leverage and complexity that will cause us to recognize various cash and noncash charges in 2015 and future years. These charges could include financing extinguishment costs, charges for unused drilling contract terminations or standby fees and charges for unused transportation and gathering capacity. If incurred, these charges would negatively 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, 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. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

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 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.

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 drilling 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 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. 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. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states 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.

The federal budget proposed in February 2015 includes provisions that would potentially increase and accelerate the payment of federal income taxes of 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 increase the severance tax rate have been proposed in Ohio 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. As a result, these competitors may be able to address these competitive factors more effectively than we can 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. Meanwhile, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries also could adversely affect 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 ultimately adversely impact our results of operations, liquidity and financial condition.

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, 2014, we did not operate approximately 10% 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 and various transportation interruptions.

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 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 adversely affect our cash flow.

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

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

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

Our headquarters are located in Oklahoma City, Oklahoma, an area that experiences severe weather events, including tornadoes and earthquakes. Our information systems and administrative and management processes are primarily provided to our various drilling projects 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.

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.

July 2008 Common Stock Offering Litigation. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company's July 2008 common stock offering. The plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. On appeal, the U.S. Court of Appeals for the Tenth Circuit affirmed the dismissal on August 8, 2014 and denied the plaintiff's petition for rehearing on November 12, 2014.

Shareholder Derivative Litigation. A derivative action relating to the July 2008 offering was filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. The case was thereafter stayed by stipulation between the parties, and on November 20, 2014, the parties entered a stipulation to have the case voluntarily dismissed. On January 16, 2015, pursuant to Court order, the Company provided notice to shareholders of the voluntary dismissal and allowed eligible shareholders to intervene.

A federal consolidated derivative action and an Oklahoma state court derivative action have been stayed since 2012 pending resolution of a related, previously reported putative federal securities class action. The shareholder derivative actions allege breaches of fiduciary duty, among other things, related to the former CEO's personal financial practices and purported conflicts of interest, and the Company's accounting for VPPs. With the dismissal of the federal securities class action now affirmed, the parties have stipulated to continue the stay of the Oklahoma state court derivative action while the plaintiffs pursue their claims in the federal consolidated derivative action. The plaintiffs filed a consolidated derivative complaint on October 31, 2014 and an amended consolidated derivative complaint on February 12, 2015. Chesapeake filed its motion to dismiss on February 23, 2015.

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 gas rights in various states. The Company also has received DOJ and state subpoenas seeking information on the Company's royalty payment practices. Chesapeake has engaged in discussions with the DOJ and state agency representatives and continues to respond to such subpoenas and demands.

On March 5, 2014, the Attorney General of the State of Michigan filed a criminal complaint against Chesapeake in Michigan state court alleging misdemeanor antitrust violations and attempted antitrust violations under state law arising out of the Company's leasing activities in Michigan during 2010. On July 9, 2014, following a preliminary hearing on the complaint, as amended, the 89th District Court for Cheboygan County, Michigan ruled that one count alleging a bid-rigging conspiracy between Chesapeake and Encana Oil & Gas USA, Inc. regarding the October 2010 state lease auction would proceed to trial and dismissed claims alleging a second antitrust violation and an attempted antitrust violation. A trial date of April 15, 2015 has been set for this case. The Michigan Attorney General filed a second criminal complaint against Chesapeake in the same court on June 5, 2014 which, as amended, alleges that Chesapeake's conduct in canceling lease offers to Michigan landowners in 2010 violated the state's criminal enterprises and false pretenses felony statutes. On September 9, 2014, following a preliminary hearing, the Court ruled that all charges in the complaint would be tried. No trial date has been set for this matter.

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 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 consolidated financial position, results of operations or cash flows. In addition, as described above, the Michigan Attorney General has commenced a criminal proceeding against us based on lease offers to Michigan landowners in 2010.

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 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 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 have 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. The plaintiff filed a motion for preliminary approval of the settlement on January 2, 2015. The Company has accrued a loss contingency for the settlement amount in the 2014 consolidated statement of operations. A fairness hearing on the settlement has been scheduled for April 17, 2015. Although Chesapeake believes that its royalty calculation and payment methodologies are appropriate under Oklahoma oil and gas law and denies that it committed any acts or omissions giving rise to any liability, it also believes that settlement is in the best interest of the Company considering the questions of law and fact involved and the uncertainty of continued litigation. There can be no assurance the court will approve the settlement, however, and the final resolution of the Oklahoma royalty claims could differ from the amount accrued.

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.

CALLC is also engaged in discussions with the PADEP regarding potential violations of the Pennsylvania Clean Streams Law as a result of pad subsidence allegedly causing material to enter a nearby stream. Since the incident, CALLC and the PADEP have been working to remediate the site and bring it into compliance. Resolution of these matters may result in monetary sanctions of more than $100,000.

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, 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
Year Ended December 31, 2013:			
Fourth Quarter	$ 29.06	$ 25.06	$ 0.0875
Third Quarter	$ 27.46	$ 20.30	$ 0.0875
Second Quarter	$ 22.86	$ 18.21	$ 0.0875
First Quarter	$ 22.97	$ 16.32	$ 0.0875

As of February 9, 2015, there were approximately 2,100 holders of record of our common stock and approximately 325,000 beneficial owners.

Although we expect to continue to pay dividends on our common stock, the payment of future cash dividends is subject to the discretion of our Board of Directors and will depend upon, among other things, our financial condition, our funds from operations, the level of our capital and development expenditures, our future business prospects, contractual restrictions and other factors considered relevant by the Board of Directors.

In addition, 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.

__Repurchases of Equity Securities__

The following table presents information about repurchases of our common stock during the quarter ended December 31, 2014:

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
				($ in millions)
October 1, 2014 through October 31, 2014	9,294	$ 22.13	—	$ —
November 1, 2014 through November 30, 2014	9,453	$ 22.00	—	—
December 1, 2014 through December 31, 2014	39,626	$ 18.53	—	1,000 [b]
Total	58,373	$ 19.67	—	$ 1,000

(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) On December 22, 2014, the Company issued a press release announcing that its Board of Directors has 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, and no repurchases had been made under the program as of December 31, 2014.

ITEM 6. *Selected Financial Data*

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2014, 2013, 2012, 2011 and 2010. The data are derived from our audited consolidated financial statements, revised to reflect the reclassification of certain items to conform to current period presentation. The table 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,				
	2014	2013	2012	2011	2010
	($ in millions, except per share data)				
REVENUES:					
Oil, natural gas and NGL	$ 8,180	$ 7,052	$ 6,278	$ 6,024	$ 5,647
Marketing, gathering and compression	12,225	9,559	5,431	5,090	3,479
Oilfield services	546	895	607	521	240
Total Revenues	20,951	17,506	12,316	11,635	9,366
OPERATING EXPENSES:					
Oil, natural gas and NGL production	1,208	1,159	1,304	1,073	893
Production taxes	232	229	188	192	157
Marketing, gathering and compression	12,236	9,461	5,312	4,967	3,352
Oilfield services	431	736	465	402	208
General and administrative	322	457	535	548	453
Restructuring and other termination costs	7	248	7	—	—
Provision for legal contingencies	234	—	—	—	—
Oil, natural gas and NGL depreciation, depletion and amortization	2,683	2,589	2,507	1,632	1,394
Depreciation and amortization of other assets	232	314	304	291	220
Impairment of oil and natural gas properties	—	—	3,315	—	—
Impairments of fixed assets and other	88	546	340	46	21
Net gains on sales of fixed assets	(199)	(302)	(267)	(437)	(137)
Total Operating Expenses	17,474	15,437	14,010	8,714	6,561
INCOME (LOSS) FROM OPERATIONS	3,477	2,069	(1,694)	2,921	2,805
OTHER INCOME (EXPENSE):					
Interest expense	(89)	(227)	(77)	(44)	(19)
Earnings (losses) on investments	(80)	(226)	(103)	156	227
Net gain (loss) on sales of investments	67	(7)	1,092	—	(129)
Losses on purchases of debt	(197)	(193)	(200)	(176)	(16)
Other income	22	26	8	23	16
Total Other Income (Expense)	(277)	(627)	720	(41)	79
INCOME (LOSS) BEFORE INCOME TAXES	3,200	1,442	(974)	2,880	2,884
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes	47	22	47	13	—
Deferred income taxes	1,097	526	(427)	1,110	1,110
Total Income Tax Expense (Benefit)	1,144	548	(380)	1,123	1,110
NET INCOME (LOSS)	2,056	894	(594)	1,757	1,774
Net income attributable to noncontrolling interests	(139)	(170)	(175)	(15)	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,917	724	(769)	1,742	1,774
Preferred stock dividends	(171)	(171)	(171)	(172)	(111)
Premium on purchase of preferred shares of a subsidiary	(447)	(69)	—	—	—
Earnings allocated to participating securities	(26)	(10)	—	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 1,273	$ 474	$ (940)	$ 1,570	$ 1,663

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	($ in millions, except per share data)				
STATEMENT OF OPERATIONS DATA (continued):					
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 1.93	$ 0.73	$ (1.46)	$ 2.47	$ 2.63
Diluted	$ 1.87	$ 0.73	$ (1.46)	$ 2.32	$ 2.51
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.35	$ 0.35	$ 0.35	$ 0.3375	$ 0.30
CASH FLOW DATA:					
Cash provided by operating activities	$ 4,634	$ 4,614	$ 2,837	$ 5,903	$ 5,117
Cash provided by (used in) investing activities	$ 454	$ (2,967)	$ (4,984)	$ (5,812)	$ (8,503)
Cash provided by (used in) financing activities	$ (1,817)	$ (1,097)	$ 2,083	$ 158	$ 3,181
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 40,751	$ 41,782	$ 41,611	$ 41,835	$ 37,179
Long-term debt, net of current maturities	$ 11,154	$ 12,886	$ 12,157	$ 10,626	$ 12,640
Total equity	$ 18,205	$ 18,140	$ 17,896	$ 17,961	$ 15,264

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,		
	2014	2013	2012
Net Production:			
Oil (mmbbl)	42.3	41.1	31.3
Natural gas (bcf)	1,095.0	1,094.6	1,128.8
NGL (mmbbl)	33.1	20.9	17.6
Oil equivalent (mmboe)[a]	257.8	244.4	237.0
Oil, Natural Gas and NGL Sales ($ in millions):			
Oil sales	$ 3,682	$ 3,911	$ 2,829
Oil derivatives - realized gains (losses)[b]	(185)	(108)	39
Oil derivatives - unrealized gains (losses)[b]	859	280	857
Total oil sales	4,356	4,083	3,725
Natural gas sales	2,777	2,430	2,004
Natural gas derivatives - realized gains (losses)[b]	(191)	9	328
Natural gas derivatives - unrealized gains (losses)[b]	535	(52)	(331)
Total natural gas sales	3,121	2,387	2,001
NGL sales	703	582	526
NGL derivatives - realized gains (losses)[b]	—	—	(9)
NGL derivatives - unrealized gains (losses)[b]	—	—	35
Total NGL sales	703	582	552
Total oil, natural gas and NGL sales	$ 8,180	$ 7,052	$ 6,278
Average Sales Price (excluding gains (losses) on derivatives):			
Oil ($ per bbl)	$ 87.13	$ 95.17	$ 90.49
Natural gas ($ per mcf)	$ 2.54	$ 2.22	$ 1.77
NGL ($ per bbl)	$ 21.27	$ 27.87	$ 29.89
Oil equivalent ($ per boe)	$ 27.78	$ 28.33	$ 22.61
Average Sales Price (including realized gains (losses) on derivatives):			
Oil ($ per bbl)	$ 82.76	$ 92.53	$ 91.74
Natural gas ($ per mcf)	$ 2.36	$ 2.23	$ 2.07
NGL ($ per bbl)	$ 21.27	$ 27.87	$ 29.37
Oil equivalent ($ per boe)	$ 26.32	$ 27.92	$ 24.12

	Years Ended December 31,		
	2014	2013	2012
Other Operating Income[(c)] ($ in millions):			
Marketing, gathering and compression net margin	$ (11)	$ 98	$ 119
Oilfield services net margin	$ 115	$ 159	$ 142
Expenses ($ per boe):			
Oil, natural gas and NGL production	$ 4.69	$ 4.74	$ 5.50
Production taxes	$ 0.90	$ 0.94	$ 0.79
General and administrative[(d)]	$ 1.25	$ 1.86	$ 2.26
Oil, natural gas and NGL depreciation, depletion and amortization	$ 10.41	$ 10.59	$ 10.58
Depreciation and amortization of other assets	$ 0.90	$ 1.28	$ 1.28
Interest expense[(e)]	$ 0.63	$ 0.65	$ 0.35
Interest Expense ($ in millions):			
Interest expense	$ 173	$ 169	$ 84
Interest rate derivatives – realized (gains) losses[(f)]	(12)	(9)	(1)
Interest rate derivatives – unrealized (gains) losses[(f)]	(72)	67	(6)
Total interest expense	$ 89	$ 227	$ 77

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

(b) Realized gains and 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 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.

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

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

(e) 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.

(f) 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

We own interests in approximately 45,100 oil and natural gas wells and produced an average of approximately 729 mboe per day in the 2014 fourth quarter, net to our interest. Our 2014 production of 258 mmboe consisted of 42 mmbbls of oil (16% on an oil equivalent basis), 1.1 tcf of natural gas (71% on an oil equivalent basis), and 33 mmbbls of NGL (13% on an oil equivalent basis). Liquids represented 29% of total production for 2014, up from 25% in 2013. Our daily production for 2014 averaged approximately 706 mboe, an increase of 5% from 2013, or 9% when adjusted for asset sales. Compared to 2013, average daily oil production increased by 3%, or approximately 3 mbbls per day; average daily natural gas production remained the same year over year, primarily as a result of asset sales; and average daily NGL production increased by 58%, or approximately 33 mbbls per day. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) increased approximately $239 million to $7.2 billion in 2014 compared to $6.9 billion in 2013, primarily due to an increase in oil and NGL volumes sold and an increase in the price received for our natural gas sold, partially offset by a decrease in the prices received for our oil and NGL sold. See *Results of Operations* below for additional details.

Capital Expenditures

Our drilling and completion capital expenditures during 2014 were approximately $4.5 billion and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other plant, property and equipment were approximately $669 million, for a total of approximately $5.1 billion compared to the Company's forecasted range of $5.0 to $5.4 billion. The level of drilling and completion expenditures represented a decrease of approximately $1.0 billion, or 18%, compared to 2013. In 2014, we operated an average of 64 rigs, a decrease of seven rigs compared to 2013. In addition to a lower rig count, drilling and completion costs were lower in 2014 than in 2013 as a result of improving capital efficiencies. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other plant, property and equipment decreased approximately $562 million, or 46%, compared to 2013. The reduction is primarily the result of a reduction in costs for construction of our corporate headquarters and field offices and for our former oilfield services business which was spun off in June 2014. Capital expenditures were also lower in 2014 because we sold substantially all of our midstream business and most of our gathering assets in 2012 and 2013.

In addition, we invested approximately $499 million and $240 million in 2014 and 2013, respectively, to purchase rigs and compressors previously sold under long-term lease arrangements 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. Both the spin-off and exchange are discussed below under *2014 Strategic Transactions.* Our capitalized interest was approximately $637 million and $816 million in 2014 and 2013, respectively. Including these items, total capital investments were approximately $6.7 billion in 2014 compared to $7.6 billion for 2013.

Based on planned activity levels for 2015, we project that drilling and completion, net leasehold, geological and geophysical and other plant, property and equipment capital expenditures will be $4.0 to $4.5 billion, inclusive of capitalized interest. This decrease from 2014 is primarily driven by substantially lower oil and natural gas prices forecasted in 2015 compared to 2014. See *Liquidity and Capital Resources* for additional information on how we plan to fund our capital budget.

2014 Strategic Transactions

We continue to pursue opportunities to high-grade our portfolio so that we can focus on assets that are best aligned with our strategy of profitable growth from captured resources. Significant strategic transactions completed in 2014 are described below.

Sale of Southern Marcellus and Utica Shale Assets

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 in December 2014. 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. Average net daily production from these properties was approximately 57,000 boe in mid-December 2014. As of December 31, 2013, net proved reserves associated with these properties were approximately 221 mmboe, or 8% of total proved reserves.

Spin-Off of Oilfield Services Business

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). Following the close of business on June 30, 2014, we distributed to Chesapeake shareholders one share of common stock of SSE and cash in lieu of fractional shares for every 14 shares of Chesapeake common stock outstanding on June 19, 2014, the record date for the distribution. Prior to the spin-off, SSE's services included drilling, hydraulic fracturing, oilfield rentals, rig relocation, and water transport and disposal. We believe the benefits of the spin-off include:

- enhancing the flexibility of the management team of Chesapeake and SSE to make strategic and operational decisions that are in the best interests of their respective businesses;
- optimizing the allocation of capital and corporate resources in a manner that focuses on achieving the strategic priorities of each company;
- enhancing SSE's ability to attract E&P customers other than Chesapeake;
- enhancing SSE's reputation as an independent provider of diversified oilfield services;
- enhancing the ability of each company to more efficiently attract and deploy capital; and
- enhancing the ability of Chesapeake and SSE to attract employees with appropriate skill sets, to incentivize their key employees with equity-based compensation that is aligned with the performance of their respective operations, and to retain key employees for the long term.

As a result of the spin-off, we have experienced the following effects:

- a reduction of approximately 5,100 employees;
- a reduction of $1.572 billion in aggregate principal amount of long-term debt as of June 30, 2014, consisting of $650 million of 6.625% Senior Notes due 2019, $500 million of 6.5% Senior Notes due 2022, a $400 million secured term loan and $22 million outstanding under SSE's new revolving credit facility; and
- the elimination of our oilfield services segment.

Powder River Basin Property Exchange

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 is currently 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 are currently designated operator. In addition to the exchange, we paid RKI approximately $450 million in cash.

Repurchase of CHK Utica Preferred Shares

We repurchased all of the outstanding preferred shares of our subsidiary CHK Utica, L.L.C. (CHK Utica) from third-party preferred shareholders for approximately $1.25 billion, or approximately $1,189 per share including accrued dividends. The transaction eliminates approximately $75 million in annual cash dividend payments to third-party preferred shareholders and also eliminates our obligation to drill and complete a minimum number of wells within a specified period for the benefit of CHK Utica. See Note 8 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for further discussion of this repurchase.

Divestitures of Noncore Oil and Natural Gas Properties

We sold noncore leasehold interests in the Marcellus Shale to a subsidiary of Rice Energy Inc. for proceeds of $233 million. We also sold noncore leasehold interests, producing properties and 61 wellhead compressor units in South Texas to Hilcorp Energy Company for proceeds of $133 million. Operating obligations related to VPP #5 were also transferred. In addition, we sold noncore leasehold interests and producing properties in East Texas and Louisiana for proceeds of $63 million. Operating obligations related to VPP #6 were also transferred. See *Volumetric Production Payments* in Note 12 of the notes to our consolidated financial statements included in Item 8 of Part II of this report.

Other Asset Sales

Midstream Compression Assets. We sold 102 compressors and related equipment to Access Midstream Partners, L.P. for approximately $159 million, and we sold 499 compressors and related equipment to Exterran Partners, L.P. for approximately $495 million.

Investments. We received $209 million of net proceeds from the sale of our common equity ownership in Chaparral Energy, Inc. We also sold an equity investment in a natural gas trading and management firm for cash proceeds of $30 million.

Buildings and Land. We sold buildings and land, located primarily in the Oklahoma City and Fort Worth areas, for proceeds of approximately $205 million. These assets were deemed noncore to our operations.

Crude Oil Hauling Assets. We sold our crude oil hauling assets for approximately $44 million.

Share Repurchase Authorization

On December 22, 2014, our Board of Directors authorized the repurchase of up to $1 billion in value of our common stock from time to time. The repurchase authorization permits us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, compliance with our debt arrangements and other appropriate factors. Acquisitions under this repurchase authorization are to be made through open market or privately negotiated transactions and may be made pursuant to plans entered into in accordance with Rule 10b5-1 of the Securities Exchange Act of 1934. This repurchase authorization does not obligate us to acquire any particular amount of common stock and may be modified, extended, suspended or discontinued at any time without prior notice. No shares had been repurchased as of February 27, 2015 and no assurance can be given that any particular amount of common stock will be repurchased.

Liquidity and Capital Resources

Liquidity Overview

Based on budgeted capital expenditures, our forecasted operating cash flow and projected levels of indebtedness, we believe we have sufficient liquidity to fund our current and long-term operations, including our contractual cash commitments to third parties pursuant to various agreements described in *Contractual Obligations and Off-Balance Sheet Arrangements* below.

As of December 31, 2014, we had approximately $8.093 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving credit facility) compared to $4.909 billion as of December 31, 2013, and we had working capital of approximately $1.373 billion compared to negative working capital of approximately $1.859 billion as of December 31, 2013. The increase in cash availability and working capital from December 31, 2013 to December 31, 2014 is primarily the result of the approximate $4.975 billion of proceeds we received in the 2014 fourth quarter from the sale of certain assets in the southern Marcellus Shale and a portion of the eastern Utica Shale. Working capital deficits have historically existed primarily due to timing differences in the initial capital outlay and the revenue stream we received over time from investing in oil and natural gas properties.

We generate cash needed to fund capital expenditures, debt obligations, dividend payments and other financial commitments primarily from our operating activities. In addition, we have supplemented our needs, enhanced our liquidity and reduced our financial leverage and complexity through divestitures of oil and gas properties, divestitures of other assets and various other transactions discussed above in *2014 Strategic Transactions*.

As a result of substantially lower oil and natural gas prices forecasted in 2015 compared to 2014, we plan to operate 35 - 45 rigs in 2015, a decrease from an average of 64 rigs in 2014, and our lowest operated rig activity level since 2004. With a lower rig count, we project that our drilling and completion, net leasehold, geological and geophysical and other capital expenditures will be $4.0 to $4.5 billion in 2015, inclusive of capitalized interest, which represents an approximate 25% reduction from 2014 levels. With this level of activity, expected 2015 prices and our current derivative contracts in place, we anticipate we may need to fund a portion of our planned capital expenditures with cash on hand. We currently have downside price protection on approximately 43% of our projected 2015 oil production at an average price of $93.39 per bbl, of which 11% is hedged under collar arrangements with upside to an average NYMEX price of $90 per bbl and exposure below an average NYMEX price of $80 per bbl. We also have downside price protection on approximately 43% of our projected 2015 natural gas production at an average price of $4.21 per mcf, of which 20% is hedged under collar arrangements with upside to an average NYMEX price of $4.29 per mcf and exposure below an average NYMEX price of $3.37 per mcf.

Management continues to review operation plans for 2015 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. We believe we have adequate flexibility to respond to negative developments if needed; however, adjustments in discretionary capital expenditures could entail penalty payments for certain of our oilfield services and midstream commitments. Our current budget anticipates having enough cash on hand to remain undrawn on our revolving credit facility as of December 31, 2015.

2014 Refinancings

In 2014, we completed refinancing transactions designed to reduce our interest and other costs and lengthen the maturity profile of our outstanding indebtedness. In December 2014, we entered into a new five-year $4.0 billion senior unsecured revolving credit facility to use for general corporate purposes. The new credit facility replaced our then-existing $4.0 billion senior secured revolving credit facility that was scheduled to mature in December 2015. The aggregate commitments under the new facility may be increased up to an additional $1.0 billion, and the December 2019 maturity date may be extended for two one-year periods at our request and with the consent of the participating lenders. As described below under *Revolving Credit Facility*, the new unsecured facility has investment grade-like terms which allowed us to release nearly $6.0 billion of proved reserve-based collateral.

In April 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 $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.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for each of the years ended December 31, 2014, 2013 and 2012. See *2014 Strategic Transactions* above and Notes 12, 14 and 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of sales of oil and natural gas assets, investments and other assets, respectively.

	Years Ended December 31,		
	2014	**2013**	**2012**
		($ in millions)	
Cash Provided by Operating Activities	$ 4,634	$ 4,614	$ 2,837
Sales of Oil and Natural Gas Assets:			
Southern Marcellus and Utica	4,970	—	—
South Texas	110	—	—
East Texas and Louisiana	58	—	—
Marcellus	231	490	—
Eagle Ford	—	636	—
Haynesville	—	304	—
SIPC (Mississippian Lime joint venture)	—	1,025	—
Permian Basin	—	—	3,130
Texoma	—	—	572
Chitwood Knox	—	—	540
Volumetric production payments	—	—	744
Joint venture leasehold	33	58	272
Other oil and natural gas properties	411	954	626
Total Sales of Oil and Natural Gas Assets	5,813	3,467	5,884
Sales of Other Assets:			
Sale of compressors to Exterran	495	—	—
Sale of compressors to ACMP	159	—	—
Sale of Chesapeake Midstream Operating, L.L.C.	—	—	2,160
Sale of Mid-America Midstream Gas Services, L.L.C.	—	306	—
Sale of Granite Wash Midstream Gas Services, L.L.C.	—	252	—
Sales of other property and equipment	349	364	332
Total Sales of Other Assets	1,003	922	2,492
Other Sources of Cash and Cash Equivalents:			
Proceeds from sales of investments	239	115	2,000
Proceeds from long-term debt, net	2,966	2,274	6,985
Proceeds from oilfield services long-term debt, net	888	—	—
Sale of preferred interest and ORRI in CHK C-T	—	—	1,250
Other	37	187	84
Total Other Sources of Cash and Cash Equivalents	4,130	2,576	10,319
Total Sources of Cash and Cash Equivalents	$ 15,580	$ 11,579	$ 21,532

Cash provided by operating activities was $4.634 billion in 2014 compared to $4.614 billion in 2013 and $2.837 billion in 2012. The increase in cash provided by operating activities from 2013 to 2014 is primarily the result of higher production volumes and decreases in certain of our operating expenses, partially offset by lower realized prices for the oil and NGL we sold. The increase in cash provided by operating activities from 2012 to 2013 is primarily the result of an increase in prices received for oil, natural gas and NGL sold, an increase in oil and NGL volumes sold 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 of other assets, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under *Results of Operations*.

The following table reflects the proceeds received from issuances of debt in 2014, 2013 and 2012. 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,					
	2014		2013		2012	
	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	$ 1,300	$ 1,263
Term loans[(a)]	400	394	—	—	6,000	5,722
Total	$ 3,900	$ 3,854	$ 2,300	$ 2,274	$ 7,300	$ 6,985

(a) 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.

Our $4.0 billion unsecured revolving credit facility and cash and cash equivalents provide other sources of liquidity. We use the facility and cash on hand to fund daily operating activities and capital expenditures as needed. 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. Prior to June 15, 2012, we also had a $600 million midstream revolving credit facility, which we terminated in June 2012. We borrowed $7.406 billion and repaid $7.788 billion in 2014, borrowed $7.669 billion and repaid $7.682 billion in 2013 and borrowed $20.318 billion and repaid $21.650 billion in 2012 under our revolving credit facilities. As of December 31, 2014, we had no outstanding borrowings under our revolving credit facility and had utilized approximately $15 million of the facility for various letters of credit. Our facility is unsecured; however, we will be required to provide collateral and the facility will be subject to a borrowing base if our credit rating declines to specified levels.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for 2014, 2013 and 2012:

	Years Ended December 31, 2014	2013	2012
	($ in millions)		
Oil and Natural Gas Expenditures:			
Drilling and completion costs[a]	$ 4,495	$ 5,490	$ 8,707
Acquisitions of proved and unproved properties	758	302	2,385
Geological and geophysical costs	35	33	170
Interest capitalized on unproved properties	604	811	829
Total Oil and Natural Gas Expenditures	5,892	6,636	12,091
Other Uses of Cash and Cash Equivalents:			
Cash paid to repurchase debt	3,362	2,141	4,000
Additions to other property and equipment	227	732	2,615
Payments on credit facility borrowings, net	382	13	1,332
Cash paid to purchase leased rigs and compressors	499	240	36
Cash paid for prepayment of mortgage	—	55	—
Cash paid to purchase preferred shares of subsidiary	1,254	212	—
Dividends paid	405	404	398
Distributions to noncontrolling interest owners	173	215	218
Cash paid to extinguish other financing	—	141	—
Cash paid for financing derivatives[b]	53	91	37
Additions to investments	17	44	395
Other	45	105	474
Total Other Uses of Cash and Cash Equivalents	6,417	4,393	9,505
Total Uses of Cash and Cash Equivalents	$ 12,309	$ 11,029	$ 21,596

(a) Net of $679 million, $884 million and $784 million in drilling and completion carries received from our joint venture partners during 2014, 2013 and 2012, respectively.

(b) 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. Historically, a significant use was also for the acquisition of leasehold and construction and acquisition of other property and equipment. During 2014, our average operated rig count was 64 rigs compared to an average rig count of 71 operated rigs in 2013 and 131 operated rigs in 2012.

Our proved and unproved property acquisition costs were $758 million in 2014 compared to $302 million in 2013 and $2.385 billion in 2012. The increase in 2014 compared to 2013 was primarily due to the Powder River Basin transaction discussed in *2014 Strategic Transactions*. Through 2012, we invested heavily in proved and unproved properties and now hold a substantial inventory of resources that provide a foundation for future growth.

Capital expenditures related to our midstream, oilfield services and other fixed assets were $227 million in 2014 compared to $732 million in 2013 and $2.615 billion in 2012, respectively. The reduction of these expenditures in 2014 as compared to 2013 and 2012 is primarily the result of the spin-off of our oilfield services business, divestiture of our midstream and gathering business and reductions in construction expenditures on our corporate headquarters and field offices.

In 2014, we used $3.362 billion of cash to reduce debt. For a discussion of the debt repaid, see *2014 Refinancings* above.

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 our 6.775% Senior Notes due 2019 (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.

In late 2012, we fully repaid the $4.0 billion term loan that we established in May 2012 with cash proceeds from asset sales and proceeds from the issuance of the $2.0 billion term loan that we established in November 2012.

In 2014, 2013 and 2012, we purchased rigs and compressors previously sold under long-term lease arrangements for approximately $499 million, $240 million and $36 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 SSE.

We paid dividends on our common stock of $234 million, $233 million and $227 million in 2014, 2013 and 2012, respectively. We paid dividends on our preferred stock of $171 million in each of 2014, 2013 and 2012.

Revolving Credit Facility

In December 2014, we entered into a new $4.0 billion senior unsecured revolving credit facility that matures in December 2019. As of December 31, 2014, we had no outstanding borrowings under the facility and utilized $15 million of the facility for various letters of credit. Borrowings under the facility bear interest at a variable rate. The applicable interest rates under the facility fluctuate based on our credit ratings. We would be required to post collateral in the event of a downgrade of our credit ratings to specified levels. 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 credit agreement) that does not exceed 65%, and (ii) a leverage ratio (net debt to consolidated EBITDA, as defined in the credit agreement) that does not exceed 4.0 to 1.0; provided, however, that the leverage ratio will not apply during any period in which our credit ratings, as determined by either Moody's Investors Services, Inc. or Standard & Poor's Ratings Services, meet and continue to meet certain investment grade thresholds, as defined in the credit agreement. As of December 31, 2014, our net debt to capitalization ratio was approximately 0.31 to 1.0, and our leverage ratio was approximately 1.55 to 1.0. We were in compliance with all financial covenants under the credit agreement as of December 31, 2014. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the terms of the credit facility.

Hedging Facility

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 1.031 bboe of hedging capacity for oil, natural gas and NGL price derivatives and 1.031 bboe for basis derivatives with an aggregate mark-to-market capacity of $16.5 billion. For further discussion of the terms of the hedging facility, 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, 2014:

	December 31, 2014
	($ in millions)
3.25% senior notes due 2016	$ 500
6.25% euro-denominated senior notes due 2017[(a)]	416
6.5% senior notes due 2017	660
7.25% senior notes due 2018	669
Floating rate senior notes due 2019	1,500
6.625% senior notes due 2020	1,300
6.875% senior notes due 2020	500
6.125% senior notes due 2021	1,000
5.375% senior notes due 2021	700
4.875% senior notes due 2022	1,500
5.75% senior notes due 2023	1,100
2.75% contingent convertible senior notes due 2035[(b)]	396
2.5% contingent convertible senior notes due 2037[(b)]	1,168
2.25% contingent convertible senior notes due 2038[(b)]	347
Discount on senior notes[(c)]	(231)
Interest rate derivatives[(d)]	10
Total senior notes, net	11,535
Less current maturities of long-term debt[(e)]	(381)
Total long-term senior notes, net	$ 11,154

(a) The principal amount shown is based on the exchange rate of $1.2098 to €1.00 as of December 31, 2014. 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 first put date, for the 2.75% Contingent Convertible Senior Notes due 2035, is November 15, 2015. 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) Included in this discount as of December 31, 2014 was $224 million associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

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

(e) 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.

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, 2014, our oil, natural gas and interest rate derivative instruments were spread among 18 counterparties. We also invested available cash balances with many of these same counterparties as well as other relationship banks. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their obligations in excess of defined thresholds. We use this facility for substantially all of our oil, natural gas and NGL derivatives.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($1.340 billion as of December 31, 2014) and exploration and production companies that own interests in properties we operate ($691 million as of December 31, 2014). 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 2014, 2013 and 2012, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2014, 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, 2014.

	Payments Due By Period				
	Total	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
			($ in millions)		
Long-term debt:					
Principal[(a)]	$ 11,756	$ 396	$ 2,744	$ 2,516	$ 6,100
Interest	4,028	590	1,109	921	1,408
Operating lease obligations[(b)]	11	5	5	1	—
Operating commitments[(c)]	17,012	2,332	4,481	3,319	6,880
Unrecognized tax benefits[(d)]	45	—	—	45	—
Standby letters of credit	15	15	—	—	—
Deferred premium on call options	181	95	86	—	—
Other	49	12	13	8	16
Total contractual cash obligations[(e)]	$ 33,097	$ 3,445	$ 8,438	$ 6,810	$ 14,404

(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, 2014 pursuant to SEC reporting requirements, was estimated to be approximately $773 million in total and $407 million for the next twelve months on an undiscounted basis and approximately $630 million and $386 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, 2014, our oil and natural gas derivative instruments consisted of swaps, collars, 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 2014, 2013 and 2012. 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, 2014 and 2013 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, 2014	December 31, 2013
	($ in millions)	
Derivative assets (liabilities):		
Oil fixed-price swaps	$ 471	$ (50)
Oil three-way collars	40	—
Oil call options	(89)	(265)
Oil basis protection swaps	—	1
Natural gas fixed-price swaps	281	(23)
Natural gas three-way collars	165	(7)
Natural gas call options	(170)	(210)
Natural gas basis protection swaps	23	3
Estimated fair value	$ 721	$ (551)

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, 2014, 2013 and 2012, accumulated other comprehensive income included unrealized losses, net of related tax effects, totaling $136 million, $159 million and $179 million, respectively, associated with commodity derivative contracts. Based upon the market prices at December 31, 2014, we expect to transfer to earnings approximately $23 million of net loss included in accumulated other comprehensive income 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, 2014, 2013 and 2012 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. 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, 2014, Chesapeake had net income of $2.056 billion, or $1.87 per diluted common share, on total revenues of $20.951 billion. This compares to net income of $894 million, or $0.73 per diluted common share, on total revenues of $17.506 billion for the year ended December 31, 2013 and a net loss of $594 million, or $1.46 per common share, on total revenues of $12.316 billion for the year ended December 31, 2012. The increase in net income in 2014 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 net loss in 2012 was primarily driven by a $2.022 billion after-tax impairment of oil and natural gas properties recorded in the 2012 third quarter. See *Impairment of Oil and Natural Gas Properties* below.

Oil, Natural Gas and NGL Sales. During 2014, oil, natural gas and NGL sales were $8.180 billion compared to $7.052 billion in 2013 and $6.278 billion in 2012. In 2014, Chesapeake produced and sold 258 mmboe for $7.162 billion at a weighted average price of $27.78 per boe (excluding the effect of derivatives), compared to 244 mmboe produced and sold in 2013 for $6.923 billion at a weighted average price of $28.33 per boe (excluding the effect of derivatives) and 237 mmboe produced and sold in 2012 for $5.359 billion at a weighted average price of $22.61 per boe (excluding the effect of derivatives). The decrease in the price received per boe in 2014 compared to 2013 resulted in a $141 million decrease in revenues, and increased sales volumes resulted in a $380 million increase in revenues, for a net increase in revenues of $239 million (excluding the effect of derivatives).

For 2014, our average price received per barrel of oil was $87.13, compared to $95.17 in 2013 and $90.49 in 2012 (excluding the effect of derivatives). Natural gas prices received per mcf (excluding the effect of derivatives) were $2.54, $2.22 and $1.77 in 2014, 2013 and 2012, respectively. NGL prices received per barrel (excluding the effect of derivatives) were $21.27, $27.87 and $29.89, in 2014, 2013 and 2012, respectively. In 2014, realized prices for natural gas increased due to the higher average Henry Hub price compared to 2013 and 2012, partially offset by higher natural gas gathering and transportation costs, primarily resulting from a fee associated with a production shortfall below the minimum volume commitment under our Barnett and Haynesville gathering agreements. In 2013, realized prices for natural gas were negatively affected by higher year-over-year natural gas gathering and transportation costs, primarily as a result of construction of midstream systems being undertaken in certain of our less mature operating areas and a fee associated with a production shortfall below the minimum volume commitment under our Barnett gathering agreement. For 2015, we expect that we will continue to see increased gathering and transportation costs, including higher minimum volume commitment fees under our Barnett and Haynesville natural gas gathering agreements.

Natural gas prices after gathering, transportation and basis differentials were $1.87 per mcf below the Henry Hub natural gas benchmark price in 2014, as compared to differentials of $1.43 per mcf in 2013 and $1.02 per mcf in 2012. This was primarily the result of significant weakening of Marcellus Shale basis differentials and increased gathering and transportation costs, including higher minimum volume commitment fees under our Barnett and Haynesville natural gas gathering agreements.

Gains and losses from our oil, natural gas and NGL derivatives resulted in a net increase in oil, natural gas and NGL revenues of $1.018 billion, $129 million and $919 million in 2014, 2013 and 2012, 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, 2014.

A change in oil, natural gas and NGL prices has a significant impact on our revenues and cash flows. Assuming our 2014 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 2014 revenues and cash flows of approximately $42 million and $41 million, respectively, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2014 revenues and cash flows of approximately $109 million and $107 million, respectively, and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease in 2014 revenues and cash flows of $33 million and $32 million, respectively.

The following tables show our production and average sales prices received by operating division for 2014, 2013 and 2012:

2014	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	35.3	89.04	580.7	2.38	16.9	23.93	148.9	58	33.08
Northern[c]	7.0	77.52	514.3	2.71	16.2	18.49	108.9	42	20.54
Total[d]	42.3	87.13	1,095.0	2.54	33.1	21.27	257.8	100%	27.78

2013	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	37.6	95.57	692.9	2.09	16.7	26.32	169.7	69	32.30
Northern[c]	3.5	90.82	401.7	2.44	4.2	33.95	74.7	31	19.28
Total[d]	41.1	95.17	1,094.6	2.22	20.9	27.87	244.4	100%	28.33

2012	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	30.3	90.78	868.0	1.68	15.8	28.78	190.8	81	24.43
Northern[c]	1.0	81.60	260.8	2.10	1.8	39.73	46.2	19	15.11
Total[d]	31.3	90.49	1,128.8	1.77	17.6	29.89	237.0	100%	22.61

(a) Average sales prices exclude gains (losses) on derivatives. Decreases in the average sales prices for our oil and NGL sold in 2014 as compared to 2013 and 2012 were primarily driven by a decrease in the West Texas Intermediate (WTI) crude oil price. The increase in the average sales price for our natural gas sold in 2014 as compared to 2013 and 2012 was primarily driven by an increase in the Henry Hub natural gas price partially offset by higher basis differentials in certain of our areas relative to the Henry Hub benchmark natural gas price and increased gathering and transportation costs in certain of our areas.

(b) Our Southern Division includes the Eagle Ford, Granite Wash, Cleveland, Tonkawa and Mississippian Lime unconventional liquids plays and the Haynesville/Bossier and Barnett unconventional natural gas shale plays. The Eagle Ford Shale accounted for approximately 19% of our estimated proved reserves by volume as of December 31, 2014. Production for the Eagle Ford Shale for 2014, 2013 and 2012 was 35.4 mmboe, 31.7 mmboe and 17.8 mmboe, respectively. The Barnett Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2014. Production for the Barnett Shale for 2014, 2013 and 2012 was 24.0 mmboe, 28.9 mmboe and 30.3 mmboe, respectively. Our gathering agreements for Barnett and Haynesville production require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. These fees amounted to $0.11 per mcf in 2014 and $0.03 per mcf in 2013, and we anticipate incurring shortfall fees in 2015 based on current production estimates.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play.

(d) 2014, 2013 and 2012 production levels reflect the impact of various asset sales and joint ventures. The decrease in production in the Southern Division in 2014 as compared to 2013 and 2012 is primarily the result of our 2013 asset sale in the Haynesville Shale, along with various asset sales and joint ventures in both 2013 and 2012. The increase in production in the Northern Division in 2014 as compared to 2013 and 2012 is primarily the result of increased processing capacity in the Utica Shale. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for information on our oil and natural gas property divestitures and joint ventures.

Our average daily production of 706 mboe for 2014 consisted of approximately 206,300 bbls of liquids, including approximately 115,800 bbls of oil (16% on an oil equivalent basis) and approximately 90,500 bbls of NGL (13% on an oil equivalent basis) and approximately 3.0 bcf of natural gas (71% on an oil equivalent basis). Our year-over-year growth rate of NGL production was 58%. Oil production increased 3% year over year and our natural gas production remained the same year over year, primarily as a result of asset sales.

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,		
	2014	2013	2012
Oil	52%	56%	53%
Natural gas	39%	36%	37%
NGL	9%	8%	10%
Total	100%	100%	100%

Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues and expenses consist of third-party revenues and expenses related to our marketing, gathering and compression operations 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 $12.225 billion in marketing, gathering and compression revenues in 2014 with corresponding expenses of $12.236 billion, for a net loss before depreciation of $11 million. This compares to revenues of $9.559 billion, expenses of $9.461 billion and a net margin before depreciation of $98 million in 2013 and revenues of $5.431 billion, expenses of $5.312 billion and a net margin before depreciation of $119 million in 2012. Revenues and operating expenses from our marketing business increased substantially in 2014 and 2013 primarily as a result of an increase in a variety of purchase and sales contracts we entered into with third parties for various commercial purposes, including credit risk mitigation and to help meet certain of our pipeline delivery commitments. In addition, we marketed more oil and NGL from Chesapeake-operated wells for third parties. The margin decrease in 2014 and 2013 as compared to 2012 was primarily a result of losses on certain sales contracts with third parties entered into to help meet certain of our oil pipeline and other commitments. In addition, margins were reduced as a result of the sale of a significant portion of our compression assets in 2014 and the sale of gathering assets in 2013.

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. Chesapeake recognized $546 million in oilfield services revenues in 2014 with corresponding expenses of $431 million, for a net margin before depreciation of $115 million. This compares to revenues of $895 million and $607 million, expenses of $736 million and $465 million with net margins before depreciation of $159 million and $142 million in 2013 and 2012, respectively. 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 the second half of 2014, and we 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 $1.208 billion in 2014, compared to $1.159 billion in 2013 and $1.304 billion in 2012. On a unit-of-production basis, production expenses were $4.69 per boe in 2014 compared to $4.74 per boe in 2013 and $5.50 in 2012. The per unit expense decrease in 2014 was primarily the result of a general improvement in operating efficiencies across most of our operating areas. Production expenses in 2014, 2013 and 2012 included approximately $157 million, $177 million and $220 million, or $0.61, $0.72 and $0.93 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 ten VPPs have been assumed by third parties as a result of our divestiture of related properties in 2014 and we purchased the remaining reserves from one of our VPPs in 2012 and subsequently sold the reserves to a buyer of our Permian Basin assets.

The following table shows our production expenses (excluding ad valorem taxes) by operating division and our ad valorem tax expenses for 2014, 2013 and 2012:

	2014			2013			2012		
	Production Expenses		$/boe	Production Expenses		$/boe	Production Expenses		$/boe
	($ in millions, except per unit)								
Southern[a]	$	882	5.92	$	925	5.46	$	1,087	5.70
Northern		229	2.10		164	2.19		143	3.10
		1,111	4.31		1,089	4.46		1,230	5.19
Ad valorem tax		97	0.38		70	0.28		74	0.31
Total	$	1,208	4.69	$	1,159	4.74	$	1,304	5.50

(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.

Production Taxes. Production taxes were $232 million in 2014 compared to $229 million in 2013 and $188 million in 2012. On a unit-of-production basis, production taxes were $0.90 per boe in 2014 compared to $0.94 per boe in 2013 and $0.79 per boe in 2012. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil, natural gas and NGL prices are higher. Production taxes in 2014, 2013 and 2012 included approximately $16 million, $22 million and $20 million, or $0.06, $0.09 and $0.08 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 three of our ten VPPs have been terminated as described in the above discussion of production expenses.

General and Administrative Expenses. General and administrative expenses were $322 million in 2014, $457 million in 2013 and $535 million in 2012, or $1.25, $1.86, and $2.26 per boe, respectively. The absolute and per unit expense decrease in 2014 was primarily due to our workforce reduction in the second half of 2013 and efforts to reduce our overhead. In addition, fair value adjustments to performance share units (PSUs), reflecting changes in the trading price of our common stock, were significantly lower in 2014 compared to 2013 and 2012. Included in general and administrative expenses is stock-based compensation of $46 million in 2014, $60 million in 2013 and $71 million in 2012. See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our stock-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 $230 million, $317 million and $434 million of internal costs in the 2014, 2013 and 2012, respectively, directly related to our oil and natural gas property acquisition and drilling and completion efforts. The decrease was primarily due to a decrease in our drilling activity, lower costs and increased emphasis on operational efficiencies.

Restructuring and Other Termination Costs. We recorded expense of $7 million, $248 million and $7 million of restructuring and other termination costs in 2014, 2013 and 2012, respectively. The 2014 amount primarily related to costs incurred related to the spin-off of our oilfield services business in June 2014. These costs were partially offset by negative fair value adjustments to PSUs granted to former executives of the Company. 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. The 2013 amount primarily related to workforce reductions, senior management separations and our voluntary separation plan. The 2012 amount related to other termination benefits. 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. 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. Adverse results in these matters would cause our obligations to royalty owners to increase, which would result in a decrease in our future revenues. 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 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 further discussion of this litigation.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $2.683 billion, $2.589 billion and $2.507 billion in 2014, 2013 and 2012, respectively. The $94 million increase in 2014 and the $82 million increase in 2013 were driven by increases in our production. 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 $10.41, $10.59 and $10.58 in 2014, 2013 and 2012, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $232 million in 2014 compared to $314 million in 2013 and $304 million in 2012. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. 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. In June 2014, we completed the spin-off of our oilfield services business and, therefore, will not incur this expense in future periods. The following table shows depreciation expense by asset class for 2014, 2013 and 2012 and the estimated useful lives of these assets.

	Years Ended December 31,			Estimated Useful Life
	2014	2013	2012	
	($ in millions)			(in years)
Oilfield services equipment[a]	$ 74	$ 122	$ 61	3 - 15
Buildings and improvements	42	47	42	10 - 39
Natural gas compressors[b]	37	35	26	3 - 20
Computers and office equipment	32	44	45	3 - 7
Vehicles	24	38	52	0 - 7
Natural gas gathering systems and treating plants[b]	12	13	46	20
Other	11	15	32	2 - 20
Total depreciation and amortization of other assets	$ 232	$ 314	$ 304	

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

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

Impairment of Oil and Natural Gas Properties. In 2012, we reported a non-cash impairment charge on our oil and natural gas properties of $3.315 billion, primarily resulting from a 10% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of September 30, 2012 compared to June 30, 2012, and the impairment of certain undeveloped leasehold, primarily in the Williston and DJ Basins. We account for our oil and natural gas properties using the full cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of oil and natural gas assets in the evaluated portion of our full cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves using a 10% pre-tax discount rate based on pricing and cost assumptions prescribed by the SEC and the present value of oil and natural gas derivative instruments designated as cash flow hedges. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our impairment of oil and natural gas properties.

The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are low. The NYMEX WTI index price of oil declined significantly from $105.37 per bbl as of June 30, 2014 to $53.27 per bbl as of December 31, 2014, and the Henry Hub index price of natural gas declined from $4.46 per mcf to $2.89 per mcf over the same period. Based on the decline in oil and natural gas prices in the second half of 2014 and into 2015, we expect to have a material write-down of the carrying value of our oil and natural gas properties in the 2015 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.

Impairments of Fixed Assets and Other. In 2014, 2013 and 2012, we recognized $88 million, $546 million and $340 million, respectively, of fixed asset impairment losses and other charges. The 2014 amount relates to charges recorded for a joint venture net acreage shortfall and 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. The 2012 amount relates to impairments of buildings and land, drilling rigs and equipment and charges for a joint venture net acreage shortfall. 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 on Sales of Fixed Assets. In 2014, net gains on sales of fixed assets were $199 million compared to $302 million in 2013 and $267 million in 2012. The 2014 amount primarily relates to the sale of natural gas compressors and crude hauling assets. The 2013 and 2012 amounts primarily relate 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 $89 million in 2014 compared to $227 million in 2013 and $77 million in 2012 as follows:

	Years Ended December 31,		
	2014	2013	2012
		($ in millions)	
Interest expense on senior notes	$ 704	$ 740	$ 732
Interest expense on term loans	36	116	173
Amortization of loan discount, issuance costs and other	42	91	89
Interest expense on credit facilities	28	38	70
Realized gains on interest rate derivatives[a]	(12)	(9)	(1)
Unrealized (gains) losses on interest rate derivatives[b]	(72)	67	(6)
Capitalized interest	(637)	(816)	(980)
Total interest expense	$ 89	$ 227	$ 77
Average senior notes borrowings	$ 11,653	$ 10,991	$ 10,487
Average term loan borrowings	$ 625	$ 2,000	$ 2,096
Average credit facilities borrowings	$ 306	$ 678	$ 2,517

(a) Includes 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.

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

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, 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. The increase in 2013 interest expense was primarily due to 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. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.63 per boe in 2014 compared to $0.65 per boe in 2013 and $0.35 per boe in 2012.

Losses on Investments. Losses on investments were $80 million in 2014 compared to losses of $226 million in 2013 and losses of $103 million in 2012. The 2014 losses primarily relate to our equity in the net losses of FTS International, Inc. (FTS) and Sundrop Fuels, Inc. (Sundrop). 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. Losses in 2012 primarily relate to our equity in the net loss of FTS. 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 Gains (Losses) on Sales of Investments. We recorded net gains on sales of investments of $67 million in 2014 compared to net losses of $7 million in 2013 and net gains of $1.092 billion in 2012. In 2014, we sold all of our interest in Chaparral Energy, Inc. for cash proceeds of $215 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. In 2012, we sold all of our common and subordinated units representing limited partner interests in Access Midstream Partners, L.P. (ACMP) and all of our limited liability company interests in the sole member of its general partner for cash proceeds of $2.0 billion. We recorded a $1.032 billion pre-tax gain associated with the transaction. Also in 2012, we sold our investment in Glass Mountain Pipeline, LLC for cash proceeds of $99 million and recorded a $62 million gain.

Losses on Purchases of Debt and Extinguishment of Other Financing. We recorded losses on purchases of debt of $197 million in 2014, $193 million in 2013 and $200 million in 2012. In December 2014, we entered into a new five-year $4.0 billion senior unsecured revolving credit facility to use for general corporate purposes. The new 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 are 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.

In 2012, we used proceeds from asset sales and our November 2012 term loan to fully repay our May 2012 term loans. We recorded $200 million of losses associated with the repayment, including $86 million of deferred charges and $114 million of debt discount.

Other Income. In 2014, other income was $22 million, compared to $26 million in 2013 and $8 million in 2012. 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. The 2012 income consisted of $1 million of interest income and $7 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $1.144 billion in 2014 and $548 million in 2013 and an income tax benefit of $380 million in 2012. Our effective income tax rate was 35.8% in 2014, 38.0% in 2013 and 39.0% in 2012. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a discussion of income tax expense (benefit).

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $139 million, $170 million and $175 million in 2014, 2013 and 2012, respectively. Net income attributable to noncontrolling interests is primarily driven by the dividends paid on preferred stock of our subsidiaries CHK Utica and CHK Cleveland Tonkawa L.L.C. (CHK C-T), in addition to income or loss related to the Chesapeake Granite Wash Trust. The decrease from 2013 to 2014 is primarily due to our repurchase of all of the outstanding preferred shares of CHK Utica from third-party preferred shareholders in 2014. 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, 2014, 2013 and 2012, the fair values of our derivatives were assets of $652 million, liabilities of $649 million and liabilities of $979 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;
- 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, 2014 and 2013, we had deferred tax assets of $1.687 billion and $1.621 billion, respectively, upon which we had a valuation allowance of $222 million and $148 million, respectively, for certain state net operating losses and tax credits that we have concluded are not more likely than not to be utilized prior to expiration.

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 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; and
- an interruption in operations at our headquarters due to a catastrophic event.

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 a wide range of derivative instruments to achieve our risk management objectives, including swaps, collars and options. All of these are described in more detail below. We typically use swaps, collars and three-way collars for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility. 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 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 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 reviewed 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 multi-counterparty secured hedging facility which requires 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, 2014, 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.
- *Collars:* These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *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, 2014, 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:						
Short-term	12.5	$ 94.58	$ —	$ —	$ —	$ 471
3-Way Collars:						
Short-term	4.4	—	98.94	80.00 / 90.00	—	40
Call Options (sold):						
Short-term	20.5	—	101.85	—	—	(9)
Long-term	24.2	—	100.07	—	—	(69)
Call Options (bought)[(a)]:						
Short-term	(8.9)	—	113.54	—	—	(11)
Total Oil						$ 422

	Volume	Weighted Average Price: Fixed	Call	Put	Differential	Fair Value: Asset (Liability)
	(tbtu)	($ per mmbtu)				($ in millions)
Natural Gas:						
Swaps:						
Short-term	238	$ 4.14	$ —	$ —	$ —	$ 265
Long-term	37	3.95	—	—	—	16
3-Way Collars:						
Short-term	207	—	4.51	3.37 / 4.29	—	165
Call Options (sold):						
Short-term	226	—	6.31	—	—	(1)
Long-term	393	—	7.93	—	—	(10)
Call Options (bought)[(b)]:						
Short-term	(226)	—	6.31	—	—	(81)
Long-term	(200)	—	6.02	—	—	(78)
Basis Protection Swaps:						
Short-term	52	—	—	—	0.55	29
Long-term	8	—	—	—	(1.02)	(6)
Total Natural Gas						$ 299
Total Oil and Natural Gas						$ 721

(a) Included in the fair value are deferred premiums of $13 million which will be included in oil, natural gas and NGL sales as realized gains (losses) in 2015.

(b) Included in the fair value are deferred premiums of $82 million and $85 million which will be included in oil, natural gas and NGL sales as realized gains (losses) in 2015 and 2016, respectively.

In addition to the open derivative positions disclosed above, as of December 31, 2014, we had $216 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, 2014
	($ in millions)
Short-term	$ 200
Long-term	16
Total	$ 216

The table below reconciles the changes in fair value of our oil and natural gas derivatives during the year ended 2014. Of the $721 million fair value asset as of December 31, 2014, an $868 million asset relates to contracts maturing in the next 12 months and a $147 million liability relates to contracts maturing after 12 months. All open derivative instruments as of December 31, 2014 are expected to mature by December 31, 2022.

		December 31, 2014
		($ in millions)
Fair value of contracts outstanding, as of January 1	$	(551)
Change in fair value of contracts		1,054
Fair value of new contracts when entered into		—
Contracts realized or otherwise settled		202
Fair value of contracts when closed		16
Fair value of contracts outstanding, as of December 31	$	721

The change in oil and natural gas prices during the year ended December 31, 2014 decreased the liability related to our derivative instruments by $1.0 billion. This unrealized gain is recorded in oil, natural gas and NGL sales. We settled contracts in 2014 that were in a liability position for $202 million. The realized losses will be recorded in oil, natural gas and NGL sales in the month of related production. We terminated contracts that were in a liability position for $16 million. The realized gain is 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, 2014, we had total debt of $11.8 billion, including $10.3 billion of fixed rate debt at interest rates averaging 5.24% and $1.5 billion of floating rate debt at an interest rate of 3.48% (three-month LIBOR plus 3.25%).

	Years of Maturity						
	2015	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
				($ in millions)			
Liabilities:							
Debt – fixed rate[(a)]	$ 396	$ 500	$ 2,244	$ 1,016	$ —	$ 6,100	$ 10,256
Average interest rate	2.75%	3.25%	4.37%	5.54%	—%	5.83%	5.24%
Debt – variable rate	$ —	$ —	$ —	$ —	$ 1,500	$ —	$ 1,500
Average interest rate	—%	—%	—%	—%	3.48%	—%	3.48%

(a) This amount does not include the discount included in debt of $231 million and interest rate derivatives of $10 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.

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, 2014, the following interest rate derivatives were outstanding:

	Notional Amount		Weighted Average Rate		Fair Value Hedge	Fair Value	
			Fixed	Floating[a]		Asset (Liability)	
	($ in millions)					($ in millions)	
Fixed to Floating:							
Swaps							
Mature 2021	$	450	6.13%	1 – 3 mL 470 bp	No	$	(12)
Floating to Fixed:							
Swaps							
Mature 2015	$	400	2.59%	6 mL	No		(5)
						$	(17)

(a) Month LIBOR has been abbreviated "mL" and basis points has been abbreviated "bp".

In addition to the open derivative positions disclosed above, as of December 31, 2014 we had $52 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains (losses) once they are transferred from our senior note liability or within interest expense as unrealized gains (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. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we will pay the counterparties $459 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 sheet as a liability of $53 million as of December 31, 2014. The euro-denominated debt in long-term debt has been adjusted to $416 million as of December 31, 2014 using an exchange rate of $1.2098 to €1.00.

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, 2014.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2014 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 27, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Chesapeake Energy Corporation

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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, 2014, 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.

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

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

/s/ PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
February 27, 2015

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2014	2013
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$ 4,108	$ 837
Restricted cash	38	75
Accounts receivable, net	2,236	2,222
Short-term derivative assets ($16 and $0 attributable to our VIE)	879	—
Deferred income tax asset	—	223
Other current assets	207	299
Total Current Assets	7,468	3,656
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)	58,594	56,157
Unproved properties	9,788	12,013
Oilfield services equipment	—	2,192
Other property and equipment	3,083	3,203
Total Property and Equipment, at Cost	71,465	73,565
Less: accumulated depreciation, depletion and amortization (($251) and ($168) attributable to our VIE)	(39,043)	(37,161)
Property and equipment held for sale, net	93	730
Total Property and Equipment, Net	32,515	37,134
LONG-TERM ASSETS:		
Investments	265	477
Long-term derivative assets	6	4
Other long-term assets	497	511
TOTAL ASSETS	$ 40,751	$ 41,782

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

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

	December 31, 2014	December 31, 2013
CURRENT LIABILITIES:		
Accounts payable	$ 2,049	$ 1,596
Current maturities of long-term debt, net	381	—
Accrued interest	150	200
Deferred income tax liabilities	207	—
Short-term derivative liabilities ($0 and $5 attributable to our VIE)	15	208
Other current liabilities ($15 and $22 attributable to our VIE)	3,061	3,511
Total Current Liabilities	5,863	5,515
LONG-TERM LIABILITIES:		
Long-term debt, net	11,154	12,886
Deferred income tax liabilities	4,185	3,407
Long-term derivative liabilities	218	445
Asset retirement obligations, net of current portion	447	405
Other long-term liabilities	679	984
Total Long-Term Liabilities	16,683	18,127
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: 664,944,232 and 666,192,371 shares issued	7	7
Paid-in capital	12,531	12,446
Retained earnings	1,483	688
Accumulated other comprehensive loss	(143)	(162)
Less: treasury stock, at cost; 1,614,312 and 2,002,029 common shares	(37)	(46)
Total Chesapeake Stockholders' Equity	16,903	15,995
Noncontrolling interests	1,302	2,145
Total Equity	18,205	18,140
TOTAL LIABILITIES AND EQUITY	$ 40,751	$ 41,782

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,		
	2014	2013	2012
	($ in millions except per share data)		
REVENUES:			
Oil, natural gas and NGL	$ 8,180	$ 7,052	$ 6,278
Marketing, gathering and compression	12,225	9,559	5,431
Oilfield services	546	895	607
Total Revenues	20,951	17,506	12,316
OPERATING EXPENSES:			
Oil, natural gas and NGL production	1,208	1,159	1,304
Production taxes	232	229	188
Marketing, gathering and compression	12,236	9,461	5,312
Oilfield services	431	736	465
General and administrative	322	457	535
Restructuring and other termination costs	7	248	7
Provision for legal contingencies	234	—	—
Oil, natural gas and NGL depreciation, depletion and amortization	2,683	2,589	2,507
Depreciation and amortization of other assets	232	314	304
Impairment of oil and natural gas properties	—	—	3,315
Impairments of fixed assets and other	88	546	340
Net gains on sales of fixed assets	(199)	(302)	(267)
Total Operating Expenses	17,474	15,437	14,010
INCOME (LOSS) FROM OPERATIONS	3,477	2,069	(1,694)
OTHER INCOME (EXPENSE):			
Interest expense	(89)	(227)	(77)
Losses on investments	(80)	(226)	(103)
Net gain (loss) on sales of investments	67	(7)	1,092
Losses on purchases of debt	(197)	(193)	(200)
Other income	22	26	8
Total Other Income (Expense)	(277)	(627)	720
INCOME (LOSS) BEFORE INCOME TAXES	3,200	1,442	(974)
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes	47	22	47
Deferred income taxes	1,097	526	(427)
Total Income Tax Expense (Benefit)	1,144	548	(380)
NET INCOME (LOSS)	2,056	894	(594)
Net income attributable to noncontrolling interests	(139)	(170)	(175)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,917	724	(769)
Preferred stock dividends	(171)	(171)	(171)
Redemption of preferred shares of a subsidiary	(447)	(69)	—
Earnings allocated to participating securities	(26)	(10)	—
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 1,273	$ 474	$ (940)
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ 1.93	$ 0.73	$ (1.46)
Diluted	$ 1.87	$ 0.73	$ (1.46)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.35	$ 0.35	$ 0.35
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	659	653	643
Diluted	772	653	643

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,		
	2014	2013	2012
	($ in millions)		
NET INCOME (LOSS)	$ 2,056	$ 894	$ (594)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Unrealized gain on derivative instruments, net of income tax expense of $0, $1 and $4	1	2	6
Reclassification of (gain) loss on settled derivative instruments, net of income tax expense (benefit) of $14, $12 and ($10)	23	20	(17)
Unrealized loss on investments, net of income tax benefit of $0, ($4) and ($4)	—	(6)	(5)
Reclassification of (gain) loss on investment, net of income tax expense of ($3), $3 and $0	(5)	4	—
Other Comprehensive Income (Loss)	19	20	(16)
COMPREHENSIVE INCOME (LOSS)	2,075	914	(610)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(139)	(170)	(175)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 1,936	$ 744	$ (785)

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,		
	2014	2013	2012
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ 2,056	$ 894	$ (594)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	2,915	2,903	2,811
Deferred income tax expense (benefit)	1,097	526	(427)
Derivative gains, net	(1,102)	(71)	(926)
Cash (payments) receipts on derivative settlements, net	(253)	(104)	226
Stock-based compensation	59	98	120
Impairment of oil and natural gas properties	—	—	3,315
Net gains on sales of fixed assets	(199)	(302)	(267)
Impairment of fixed assets and other	58	483	316
Losses on investments	80	229	164
Net (gains) losses on sales of investments	(67)	7	(1,092)
Restructuring and other termination costs	(15)	175	2
Provision for legal contingencies	234	—	—
Losses on purchases of debt	63	40	200
Other	100	80	72
(Increase) decrease in accounts receivable and other assets	(21)	5	(68)
Decrease in accounts payable, accrued liabilities and other	(371)	(349)	(1,015)
Net Cash Provided By Operating Activities	4,634	4,614	2,837
CASH FLOWS FROM INVESTING ACTIVITIES:			
Drilling and completion costs	(4,581)	(5,604)	(8,930)
Acquisitions of proved and unproved properties	(1,311)	(1,032)	(3,161)
Proceeds from divestitures of proved and unproved properties	5,813	3,467	5,884
Additions to other property and equipment	(726)	(972)	(2,651)
Proceeds from sales of other property and equipment	1,003	922	2,492
Additions to investments	(17)	(44)	(395)
Proceeds from sales of investments	239	115	2,000
Decrease (increase) in restricted cash	37	177	(222)
Other	(3)	4	(1)
Net Cash Provided By (Used In) Investing Activities	454	(2,967)	(4,984)

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

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

CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	7,406	7,669	20,318
Payments on credit facilities borrowings	(7,788)	(7,682)	(21,650)
Proceeds from issuance of senior notes, net of discount and offering costs	2,966	2,274	1,263
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 discount and offering costs	394	—	—
Proceeds from issuance of term loan, net of issuance costs	—	—	5,722
Cash paid to purchase debt	(3,362)	(2,141)	(4,000)
Cash paid for common stock dividends	(234)	(233)	(227)
Cash paid for preferred stock dividends	(171)	(171)	(171)
Cash paid to extinguish other financing	—	(141)	—
Cash paid on financing derivatives	(53)	(91)	(37)
Cash paid for prepayment of mortgage	—	(55)	—
Proceeds from sales of noncontrolling interests	—	6	1,077
Proceeds from other financings	—	—	257
Cash paid to purchase preferred shares of a subsidiary	(1,254)	(212)	—
Cash held and retained by SSE at spin-off	(8)	—	—
Distributions to noncontrolling interest owners	(173)	(215)	(218)
Other	(34)	(105)	(251)
Net Cash Provided By (Used In) Financing Activities	(1,817)	(1,097)	2,083
Net increase (decrease) in cash and cash equivalents	3,271	550	(64)
Cash and cash equivalents, beginning of period	837	287	351
Cash and cash equivalents, end of period	$ 4,108	$ 837	$ 287

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

SUPPLEMENTAL CASH FLOW INFORMATION:			
Interest paid, net of capitalized interest	$ 96	$ 43	$ —
Income taxes paid, net of refunds received	$ 10	$ 26	$ 44
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Change in accrued drilling and completion costs	$ (84)	$ (63)	$ (75)
Change in accrued acquisitions of proved and unproved properties	$ (74)	$ (1)	$ 242
Change in accrued additions to other property and equipment	$ (11)	$ (81)	$ (25)

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,		
	2014	2013	2012
	($ 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	12,446	12,293	12,146
Stock-based compensation	47	162	174
Exercise of stock options	23	4	3
Increase (decrease) in tax benefit from stock-based compensation	15	(13)	(30)
Balance, end of period	12,531	12,446	12,293
RETAINED EARNINGS:			
Balance, beginning of period	688	437	1,608
Net income (loss) attributable to Chesapeake	1,917	724	(769)
Dividends on common stock	(234)	(233)	(231)
Dividends on preferred stock	(171)	(171)	(171)
Spin-off of oilfield services business (Note 13)	(270)	—	—
Redemption of preferred shares of a subsidiary	(447)	(69)	—
Balance, end of period	1,483	688	437
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(162)	(182)	(166)
Hedging activity	24	22	(11)
Investment activity	(5)	(2)	(5)
Balance, end of period	(143)	(162)	(182)
TREASURY STOCK – COMMON:			
Balance, beginning of period	(46)	(48)	(33)
Purchase of 34,678, 251,403 and 652,443 shares for company benefit plans	(1)	(6)	(16)
Release of 422,395, 397,098 and 57,252 shares from company benefit plans	10	8	1
Balance, end of period	(37)	(46)	(48)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	16,903	15,995	15,569
NONCONTROLLING INTERESTS:			
Balance, beginning of period	2,145	2,327	1,337
Sales of noncontrolling interests	—	6	1,077
Net income attributable to noncontrolling interests	139	170	175
Distributions to noncontrolling interest owners	(169)	(215)	(218)
Redemption of preferred shares of a subsidiary	(807)	(143)	—
Deconsolidation of investments, net	(6)	—	(44)
Balance, end of period	1,302	2,145	2,327
TOTAL EQUITY	$ 18,205	$ 18,140	$ 17,896

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.

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 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. Restricted cash consists 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) and, prior to our repurchase of all of the outstanding preferred shares of CHK Utica, L.L.C. (CHK Utica) in 2014, also consisted of a balance required to be maintained by the terms of the agreement governing the activities of CHK Utica. The repurchase of outstanding preferred shares of CHK Utica eliminated the restricted cash maintenance requirement related to this entity. See Note 8 for further discussion of these entities.

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 we believe may be uncollectible. During 2014, 2013 and 2012, we recognized $2 million, $2 million and a nominal amount of bad debt expense related to potentially uncollectible receivables, and we reduced our allowance by $3 million in 2013 as we wrote off specific receivables against our allowance. Accounts receivable as of December 31, 2014 and 2013 are detailed below.

	December 31,	
	2014	2013
	($ in millions)	
Oil, natural gas and NGL sales	$ 1,340	$ 1,548
Joint interest	691	417
Oilfield services[(a)]	—	63
Related parties[(b)]	—	62
Other	226	150
Allowance for doubtful accounts	(21)	(18)
Total accounts receivable, net	$ 2,236	$ 2,222

(a) In 2014, in connection with the spin-off of our oilfield services business, accounts receivable related to oilfield services were removed from our consolidated balance sheet.

(b) See Note 7 for discussion of related party transactions.

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, 2014 were prepared by independent engineering firms and Chesapeake's internal staff. Approximately 79% of these proved reserves estimates (by volume) as of December 31, 2014 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 leasehold that 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, 2014 and the year in which the associated costs were incurred.

	Year of Acquisition				
	2014	2013	2012	Prior	Total
			($ in millions)		
Leasehold acquisition cost	$ 577	$ 199	$ 1,462	$ 5,149	$ 7,387
Exploration cost	340	90	244	42	716
Capitalized interest	492	421	325	447	1,685
Total	$ 1,409	$ 710	$ 2,031	$ 5,638	$ 9,788

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, 2014, 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 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, and substantially all of our natural gas gathering systems and treating plants were sold in 2013 and 2012 as discussed in Note 16. 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 and a summary of our other property and equipment held for sale as of December 31, 2014 and 2013. 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 2014, 2013 and 2012, 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 cost 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.

Goodwill

Goodwill represents the excess of the purchase price of a business combination over the fair value of the net assets acquired and is tested for impairment at least annually. This test includes an assessment of qualitative and quantitative factors. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. When the qualitative assessment indicates that it is more likely than not that the fair value of the reporting unit is less than its carrying amount, the quantitative assessment is then performed. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense.

Our goodwill, which is included in other long-term assets on our consolidated balance sheets, was $15 million and $43 million, respectively, as of December 31, 2014 and 2013. The 2014 amount consists of $15 million of excess consideration over the fair value of assets acquired in our Horizon Drilling Services acquisition in 2011. The 2013 amount also included $28 million of excess consideration over the fair value of assets acquired in our Bronco Drilling Company acquisition in 2011. We no longer have the goodwill balance related to Bronco Drilling Company as a result of the spin-off of our oilfield services business in June 2014. We performed annual impairment tests of goodwill in the fourth quarters of 2014 and 2013. Based on these assessments, no impairment of goodwill was required. Goodwill was included in our exploration and production segment as of December 31, 2014 and as of December 31, 2013 was included in our former oilfield services segment.

Accounts Payable

Included in accounts payable as of December 31, 2014 and 2013 are liabilities of approximately $333 million and $397 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, hedging facility and, as of December 31, 2013, costs associated with our former term loan and former oilfield services credit facility. The remaining unamortized issuance costs as of December 31, 2014 and 2013 totaled $130 million and $145 million, respectively, and are being amortized over the life of the applicable debt or 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 and gathering and transportation charges.

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, 2014 and 2013 was $12 million and $11 million, respectively.

Marketing, Gathering and Compression Sales. Chesapeake takes title to the oil, natural gas and NGL it purchases from other interest owners in operated wells 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, oilfield rentals, oilfield trucking and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties. Our oilfield services revenues prior to the spin-off were as follows:

- *Drilling.* Revenues were generated by drilling oil and natural gas wells for our customers under daywork contracts and recognized for the days completed based on the dayrate specified in each contract. Revenue generated and costs incurred for mobilization services were recognized over the days of actual mobilization.
- *Hydraulic Fracturing.* Revenue was recognized upon the completion of each fracturing stage. Typically, one or more fracturing stages per day per active crew was completed during the course of a job. A stage was considered complete when the customer requested or the job design dictated that pumping discontinue for that stage. Invoices typically included a lump sum equipment charge determined by the rate per stage specified in each contract and product charges for sand, chemicals and other products actually consumed during the course of providing fracturing services.
- *Oilfield Rentals*. Oilfield equipment rentals included drill pipe, drill collars, tubing, blowout preventers, and frac and mud tanks, and services included air drilling services and services associated with the transfer of fresh water to the wellsite. Rentals and services were priced by the day or hour based on the type of equipment rented and the service job performed. Revenue was recognized ratably over the term of the rental.
- *Oilfield Trucking*. Oilfield trucking provided rig relocation and logistics services as well as fluid handling services. Trucks moved drilling rigs, crude oil, other fluids and construction materials to and from the wellsites and also transported produced water from the wellsites. These services were priced on a per barrel basis based on mileage and revenue was recognized as services were performed.
- *Other Operations.* A manufacturing subsidiary designed, engineered and fabricated natural gas compressor packages that were purchased primarily by Chesapeake. Compression units were priced based on certain specifications such as horsepower, stages and additional options. Revenue was recognized upon completion and transfer of ownership of the natural gas compression unit.

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 senior notes. We have elected not to designate any of our qualifying commodity and interest rate derivatives as cash flow or fair value hedges. Therefore, changes in fair value of these derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are recognized in our consolidated statements of operations within oil, natural gas and NGL sales and interest expense, respectively.

Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows. All of our derivative instruments are subject to master netting arrangements by contract type (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 compensation expense in the consolidated statements of operations.

To the extent compensation cost 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 the consolidated financial statements for 2012 and 2013 to conform to the presentation used for the 2014 consolidated financial statements.

2. Earnings Per Share

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

Diluted EPS is calculated assuming the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. For the years ended December 31, 2014, 2013 and 2012, 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, 2014, 2013 and 2012, 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. The impact of our stock options was immaterial in the calculation of diluted EPS for these periods.

	Net Income Adjustments ($ in millions)	Shares (in millions)
Year Ended December 31, 2014		
Participating securities	$ 22	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
Year Ended December 31, 2012		
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	39
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	5
4.50% cumulative convertible preferred stock	$ 12	6
Participating securities	$ —	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, 2014 and 2013:

	December 31, 2014	December 31, 2013
	($ in millions)	
Term loan due 2017[(a)]	$ —	$ 2,000
9.5% senior notes due 2015[(b)]	—	1,265
3.25% senior notes due 2016	500	500
6.25% euro-denominated senior notes due 2017[(c)]	416	473
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018[(d)]	—	97
7.25% senior notes due 2018	669	669
Floating rate senior notes due 2019	1,500	—
6.625% senior notes due 2019[(e)]	—	650
6.625% senior notes due 2020	1,300	1,300
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	1,000
5.375% senior notes due 2021	700	700
4.875% senior notes due 2022	1,500	—
5.75% senior notes due 2023	1,100	1,100
2.75% contingent convertible senior notes due 2035[(f)]	396	396
2.5% contingent convertible senior notes due 2037[(f)]	1,168	1,168
2.25% contingent convertible senior notes due 2038[(f)]	347	347
Revolving credit facility	—	—
Oilfield services revolving credit facility[(g)]	—	405
Discount on senior notes and term loan[(h)]	(231)	(357)
Interest rate derivatives[(i)]	10	13
Total debt, net	11,535	12,886
Less current maturities of long-term debt, net[(j)]	(381)	—
Total long-term debt, net	$ 11,154	$ 12,886

(a) In 2014, we repaid the borrowings outstanding under and terminated the term loan due 2017.

(b) In 2014, we completed a tender offer for a portion of the 9.5% Senior Notes due 2015, and we redeemed the remaining balance of the notes.

(c) The principal amount shown is based on the exchange rate of $1.2098 to €1.00 and $1.3743 to €1.00 as of December 31, 2014 and 2013, respectively. See Note 11 for information on our related foreign currency derivatives.

(d) In 2014, we redeemed all outstanding 6.875% Senior Notes due 2018.

(e) Initial issuers were Chesapeake Oilfield Operating, L.L.C. (COO) and Chesapeake Oilfield Finance, Inc., a wholly owned subsidiary of COO. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes. In 2014, in connection with the spin-off of our oilfield services business, the obligations with respect to the COO senior notes were removed from our consolidated balance sheet. See Note 13 for further discussion of the spin-off.

(f) 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 such 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 2014, 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 2015 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 in 2014, 2013 or 2012. 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 the dividend of SSE common stock paid in the spin-off of our oilfield services business and 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, 2015, 2020, 2025, 2030	$ 45.14	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 59.71	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 100.35	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.

(g) In 2014, in connection with the spin-off of our oilfield services business, we terminated our oilfield services credit facility. See Note 13 for further discussion of the spin-off.

(h) Discount as of December 31, 2014 and 2013 included $224 million and $303 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method. Discount also included $33 million as of December 31, 2013 associated with our term loan due 2017 discussed below.

(i) See Note 11 for further discussion related to these instruments.

(j) 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 (f) above, the holders of our 2.75% Contingent Convertible Senior Notes due 2035 could exercise their individual demand repurchase rights on November 15, 2015, which would require us to repurchase all or a portion of the principal amount of the 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, 2014 and thereafter are as follows:

	Principal Amount of Debt Securities
	($ in millions)
2015	$ 396
2016	500
2017	2,244
2018	1,016
2019	1,500
2020 and thereafter	6,100
Total	$ 11,756

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.

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 is a holding company, owns no operating assets and has no significant operations independent of its subsidiaries. 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 100% 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. The senior notes and contingent convertible senior notes indentures 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 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 filed a motion in 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 at the statutory 9% rate from the redemption date. The Company intends to oppose the trustee's motion vigorously.

On December 30, 2014, six former holders of the 2019 Notes filed a putative class action against the Company on behalf of all former holders who sold the 2019 Notes after the Company issued the notice of early redemption in March 2013 but before the notes were redeemed at par in May 2013. These former holders allege that the Company breached the indenture by issuing a wrongful notice of special early redemption, and that this breach caused the market value of the notes to decline, injuring them when they sold their 2019 Notes. This suit has been assigned to the same District Court judge as the suit described above. The Company intends to defend itself against this claim vigorously.

No scheduled principal payments are required on our senior notes until 2016 unless the holders of our 2.75% Contingent Convertible Senior Notes due 2035 exercise their individual demand repurchase rights on November 15, 2015, which would require us to repurchase all or a portion of the $396 million principal amount of notes.

Revolving Credit Facility

In December 2014, we entered into a new five-year $4.0 billion senior unsecured revolving credit facility to use for general corporate purposes. The new credit facility replaced our then-existing $4.0 billion senior secured revolving credit facility that was scheduled to mature in December 2015. The aggregate commitments under the facility may be increased up to an additional $1.0 billion, and the December 2019 maturity date may be extended for two one-year periods at our request and with the consent of the participating lenders. As of December 31, 2014, we had no outstanding borrowings under the facility and utilized $15 million of the facility for various letters of credit. Borrowings under the facility are currently unsecured; however, we will be required to provide collateral and the facility will be subject to a borrowing base if our credit rating declines to Ba3 (Moody's Investors Services, Inc.) or BB- (Standard & Poor's Ratings Services) or lower.

Revolving loans under the revolving credit facility bear interest at a fluctuating rate per annum equal to the highest of (i) the federal funds effective rate plus 0.5%, (ii) the administrative agent's prime rate or (iii) the London interbank offer rate (LIBOR) for a one-month interest period plus 1.0% (alternative base rate (ABR) loans), and/or LIBOR rates (LIBOR loans), at our election, plus an applicable margin rate depending on our credit rating (currently 0.625% per annum for ABR loans and 1.625% per annum for LIBOR loans). The terms of the credit facility include covenants limiting, among other things, the ability of the Company and its restricted subsidiaries to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates. In addition, the credit facility requires us to maintain, as of the last day of each fiscal quarter, (i) a net debt to capitalization ratio (as defined in the credit agreement) that does not exceed 65%; and (ii) a leverage ratio (net debt to consolidated EBITDA, as defined in the credit agreement) that does not exceed 4.0 to 1.0; provided, however, that the leverage ratio will not apply during any period in which our credit rating, as determined by either Moody's Investors Services, Inc. or Standard & Poor's Rating Services, meet and continue to meet certain investment grade thresholds, as defined in the credit agreement.

Our credit facility is fully and unconditionally guaranteed, on a joint and several basis, by certain of our material subsidiaries. The 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.

Spin-Off Debt Transactions

Prior to the spin-off of our oilfield services business, 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 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 currently consists of our revolving credit facility and as of December 31, 2013 also consisted of our former oilfield services credit facility and term loan, 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, 2014		December 31, 2013	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt (Level 1)	$ 11,525	$ 12,052	$ 10,501	$ 11,557
Long-term debt (Level 2)	$ —	$ —	$ 2,372	$ 2,369

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.

July 2008 Common Stock Offering Litigation. On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the Company and certain of its officers and directors along with certain underwriters of the Company's July 2008 common stock offering. The plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. On appeal, the U.S. Court of Appeals for the Tenth Circuit affirmed the dismissal on August 8, 2014 and denied the plaintiffs' petition for rehearing on November 12, 2014.

Shareholder Derivative Litigation. A derivative action relating to the July 2008 offering was filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. The case was thereafter stayed by stipulation between the parties, and on November 20, 2014, the parties entered a stipulation to have the case voluntarily dismissed. On January 16, 2015, pursuant to Court order, the Company provided notice to shareholders of the voluntary dismissal and allowed eligible shareholders to intervene.

A federal consolidated derivative action and an Oklahoma state court derivative action have been stayed since 2012 pending resolution of a related, previously reported putative federal securities class action. The shareholder derivative actions allege breaches of fiduciary duty, among other things, related to the former CEO's personal financial practices and purported conflicts of interest, and the Company's accounting for volumetric production payments. With the dismissal of the federal securities class action now affirmed, the parties have stipulated to continue the stay of the Oklahoma state court derivative action while the plaintiffs pursue their claims in the federal consolidated derivative action. The plaintiffs filed a consolidated derivative complaint on October 31, 2014 and an amended consolidated derivative complaint on February 12, 2015. Chesapeake filed its motion to dismiss on February 23, 2015.

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 gas rights in various states. The Company also has received DOJ and state subpoenas seeking information on the Company's royalty payment practices. Chesapeake has engaged in discussions with the DOJ and state representatives and continues to respond to such subpoenas and demands.

On March 5, 2014, the Attorney General of the State of Michigan filed a criminal complaint against Chesapeake in Michigan state court alleging misdemeanor antitrust violations and attempted antitrust violations under state law arising out of the Company's leasing activities in Michigan during 2010. On July 9, 2014, following a preliminary hearing on the complaint, as amended, the 89th District Court for Cheboygan County, Michigan ruled that one count alleging a bid-rigging conspiracy between Chesapeake and Encana Oil & Gas USA, Inc. regarding the October 2010 state lease auction would proceed to trial and dismissed claims alleging a second antitrust violation and an attempted antitrust violation. A trial date of April 15, 2015 has been set for this case. The Michigan Attorney General filed a second criminal complaint against Chesapeake in the same court on June 5, 2014 which, as amended, alleges that Chesapeake's conduct in canceling lease offers to Michigan landowners in 2010 violated the state's criminal enterprises and false pretenses felony statutes. On September 9, 2014, following a preliminary hearing, the Court ruled that all charges in the complaint would be tried. No trial date has been set for this matter.

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 have accrued a loss contingency of $100 million for this matter. We estimate the range of potential loss between $100 million to $380 million, plus prejudgment interest of up to 9%. The high end of this range is based upon the indenture trustee's request in mid-February 2015 that the Court order us to pay noteholders the "make-whole" amount (as defined in the indenture) less the par amount already paid. Our $100 million accrual is based on an estimate of the remedy required to restore the redeemed noteholders and the Company to the economic positions they would have been in had the 2019 Notes not been redeemed. We are unable to estimate an amount or range of loss with respect to the recently filed putative class action by certain former holders of the 2019 Notes.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, 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 consolidated financial position, results of operations or cash flows. In addition, as described above, the Michigan Attorney General has commenced a criminal proceeding against us based on lease offers to Michigan landowners in 2010.

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 for royalty underpayment in various states, including 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 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 have 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. The plaintiff filed a motion for preliminary approval of the settlement on January 2, 2015. The Company has accrued a loss contingency for the settlement amount in the 2014 consolidated statement of operations. A fairness hearing on the settlement has been scheduled for April 17, 2015. Although Chesapeake believes that its royalty calculation and payment methodologies are appropriate under Oklahoma oil and gas law and denies that it committed any acts or omissions giving rise to any liability, it also believes that settlement is in the best interest of the Company considering the questions of law and fact involved and the uncertainty of continued litigation. There can be no assurance the court will approve the settlement, however, and the final resolution of the Oklahoma royalty claims could differ from the amount accrued.

We believe losses are reasonably possible in certain of the other 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. In Pennsylvania, three putative statewide class actions and one purported class arbitration 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 Pennsylvania 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. 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, 2014
	($ in millions)
2015	$ 5
2016	4
2017	1
2018	1
Total	$ 11

Lease expense for the years ended December 31, 2014, 2013 and 2012 was $33 million, $158 million and $185 million, respectively. Lease expense decreased significantly in 2014 primarily due to the repurchase of all rigs and compressors previously sold under long-term sale-leaseback arrangements.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of natural gas and liquids 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 adjustments to oil, natural gas and NGL sales prices used 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 or credits for third-party volumes, are presented below.

	December 31, 2014
	($ in millions)
2015	$ 1,855
2016	1,987
2017	2,003
2018	1,802
2019	1,516
2020 - 2099	6,880
Total	$ 16,043

In addition to the gathering, processing and transportation agreements discussed above, 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 will vary depending on the applicable agreement. Two of these agreements, one for production in the Anadarko Basin and the other for production in the Haynesville/Bossier Shales in northwestern Louisiana, contain cost-of-service based fees that are redetermined annually through 2019 and 2020, respectively. The annual upward or downward fee adjustment for these two contracts 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, including those entered into with Seventy Seven Energy Inc. (SSE) in connection with the spin-off of our oilfield services business as discussed in Note 13, 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, 2014, the aggregate undiscounted minimum future payments under these drilling service commitments are detailed below.

	December 31, 2014
	($ in millions)
2015	$ 232
2016	179
2017	91
Total	$ 502

Pressure Pumping Contracts

As discussed in Note 13, in connection with the spin-off of our oilfield services business we entered into an agreement with a subsidiary of SSE related to 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. The aggregate undiscounted minimum future payments under this agreement are detailed below.

	December 31, 2014
	($ in millions)
2015	$ 245
2016	162
2017	59
Total	$ 466

Drilling Commitments

We have committed to drill wells for the benefit of CHK Cleveland Tonkawa, L.L.C. and Chesapeake Granite Wash Trust. See *Noncontrolling Interests* in Note 8 for discussion of these commitments.

Natural Gas and Liquids Purchase Commitments

We regularly commit to purchase natural gas and liquids from other owners in the properties we operate, including owners associated with our volumetric production payment (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 Note 12 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Total and Sinopec (see 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. To date, we have satisfied our replacement commitments under the Sinopec agreement. In 2014, we settled a dispute with Total regarding our acreage maintenance obligation as of December 31, 2012 for $50 million. The payment was based on a shortfall of approximately 20,800 net acres.

Other Commitments

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc. (Sundrop), a privately held cellulosic biofuels company based in Longmont, Colorado. We also provided Sundrop with a one-time option to require us to purchase up to $25 million in additional preferred equity securities following the full payment of the initial investment, subject to the occurrence of specified milestones. As of December 31, 2014, we had funded our $155 million commitment in full and the milestones related to Sundrop's preferred equity call option had not been met. See Note 14 for further discussion of this investment.

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 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 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, certain actions that may reduce financial leverage and complexity could negatively impact our future results of operations and/or liquidity, and we may incur additional cash and noncash charges.

5. Other Liabilities

Other current liabilities as of December 31, 2014 and 2013 are detailed below.

	December 31,	
	2014	2013
	($ in millions)	
Revenues and royalties due others	$ 1,176	$ 1,409
Accrued oil, natural gas and NGL drilling and production costs	385	457
Joint interest prepayments received	189	464
Accrued compensation and benefits	344	320
Other accrued taxes	55	161
Accrued dividends	101	101
Other	811	599
Total other current liabilities	$ 3,061	$ 3,511

Other long-term liabilities as of December 31, 2014 and 2013 are detailed below.

	December 31,	
	2014	2013
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$ 220	$ 250
CHK C-T ORRI conveyance obligation[(b)]	135	149
Financing obligations	30	31
Unrecognized tax benefits	45	317
Other	249	237
Total other long-term liabilities	$ 679	$ 984

(a) $14 million and $13 million of the total $234 million and $263 million obligations are recorded in other current liabilities as of December 31, 2014 and 2013, respectively. See *Noncontrolling Interests* in Note 8 for further discussion of the transaction.

(b) $23 million and $12 million of the total $158 million and $161 million obligations are recorded in other current liabilities as of December 31, 2014 and 2013, respectively. See *Noncontrolling Interests* in Note 8 for further discussion of the transaction.

6. Income Taxes

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

	Years Ended December 31,		
	2014	2013	2012
	($ in millions)		
Current			
Federal	$ —	$ —	$ —
State	47	22	47
Current Income Taxes	47	22	47
Deferred			
Federal	1,115	502	(358)
State	(18)	24	(69)
Deferred Income Taxes	1,097	526	(427)
Total	$ 1,144	$ 548	$ (380)

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,		
	2014	2013	2012
	($ in millions)		
Income tax expense (benefit) at the federal statutory rate (35%)	$ 1,120	$ 505	$ (341)
State income taxes (net of federal income tax benefit)	68	88	(38)
Remeasurement of state deferred tax liabilities	(114)	(38)	(19)
Change in valuation allowance	74	(12)	—
Other	(4)	5	18
Total	$ 1,144	$ 548	$ (380)

During the 2014 fourth quarter, Chesapeake simplified its organizational structure which impacts how income (loss) is allocated and apportioned to various states. This change resulted in a $114 million tax benefit due to the remeasurement of state deferred tax liabilities. Additionally, we reassessed the realizability of our deferred tax assets given the decline in commodity prices. We recorded a $74 million tax expense 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,	
	2014	2013
	($ in millions)	
Deferred tax liabilities:		
Oil and natural gas properties	$ (3,950)	$ (2,631)
Other property and equipment	(14)	(371)
Volumetric production payments	(920)	(1,216)
Contingent convertible debt	(443)	(439)
Deferred revenue	(102)	—
Derivative instruments	(428)	—
Deferred tax liabilities	(5,857)	(4,657)
Deferred tax assets:		
Net operating loss carryforwards (carrybacks)	945	535
Derivative instruments	—	108
Asset retirement obligations	165	153
Investments	88	130
Deferred stock compensation	50	66
Accrued liabilities	214	120
Noncontrolling interest liabilities	135	152
Alternative minimum tax credits	34	317
Other	56	40
Deferred tax assets	1,687	1,621
Valuation allowance	(222)	(148)
Net deferred tax assets	1,465	1,473
Net deferred tax assets (liabilities)	$ (4,392)	$ (3,184)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	—	223
Current deferred income tax liability	(207)	—
Non-current deferred income tax liability	(4,185)	(3,407)
Total	$ (4,392)	$ (3,184)

As of December 31, 2014, Chesapeake had federal income tax NOL carryforwards of approximately $1.6 billion and state NOL carryforwards of approximately $8.3 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 $551 million and $394 million, respectively. Additionally, we had $76 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 2033. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income. As of December 31, 2014 and 2013, we had deferred tax assets of $1.687 billion and $1.621 billion, respectively, upon which we had a valuation allowance of $222 million and $148 million, respectively, for certain state NOL carryforwards and credits that we have concluded are not more likely than not to be utilized prior to expiration. The net change in the valuation allowance of $74 million is reflected as a component of income tax expense.

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, 2014 totaled $18 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, 2014, we do not believe that an ownership change has occurred that would limit the carryforwards. Due to the spin-off of SSE, the limitation on previously acquired NOLs was increased such that the remaining carryforward became fully available. 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, 2014 and 2013, the amount of unrecognized tax benefits related to NOL carryforwards and state tax liabilities associated with uncertain tax positions was $303 million and $644 million, respectively. 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. Of the 2013 amount, $4 million is related to state tax liabilities while the remainder is related to NOL carryforwards. If these unrecognized tax benefits are disallowed and our NOL carryforwards are reduced, the reduction will be offset by additional tax basis that will generate future deductions. 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, 2014 and 2013, we had accrued liabilities of $5 million and $13 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:

	2014	2013	2012
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 644	$ 599	$ 369
Additions based on tax positions related to the current year	13	15	134
Additions to tax positions of prior years	—	30	96
Reductions to tax positions of prior years	(354)	—	—
Unrecognized tax benefits at end of period	$ 303	$ 644	$ 599

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 2007 through 2013. The federal tax returns for 1999 through 2006 remain subject to examination for the purpose of determining the amount of remaining tax NOL and other carryforwards. The 2007 through 2014 years remain open for all purposes of examination by the IRS and other taxing authorities in material jurisdictions.

7. Related Party Transactions

Our equity method investees are considered related parties. During 2014, 2013 and 2012, we had the following transactions with our equity method investees:

	Years Ended December 31, 2014	2013	2012
	($ in millions)		
Purchases[a]	$ —	$ —	$ 73
Sales[b]	$ —	$ 666	$ 392
Services[c]	$ 220	$ 397	$ 480

(a) Purchase of equipment from FTS International, Inc. (FTS).

(b) In 2013 and 2012, 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.

(c) Hydraulic fracturing and other services provided to us by FTS 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.

The table below shows the total amounts due from and due to our equity method investees.

	December 31, 2014	2013	2012
	($ in millions)		
Amounts due from equity method investees	$ —	$ 47	$ 67
Amounts due to equity method investees	$ —	$ 1	$ 42

8. Equity

Common Stock

The following is a summary of the changes in our common shares issued for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31, 2014	2013	2012
	(in thousands)		
Shares issued as of January 1	666,192	666,468	660,888
Restricted stock issuances (net of forfeitures and cancellations)[a]	(2,529)	(599)	5,038
Stock option exercises	1,281	323	542
Shares issued as of December 31	664,944	666,192	666,468

(a) In the second quarter of 2013, we began granting restricted stock units (RSUs) in lieu of restricted stock awards (RSAs) to non-employee directors and employees. Shares of common stock underlying RSUs are issued when the units vest, whereas shares of common stock are issued on the date the RSAs are granted. We refer to RSAs and RSUs collectively as restricted stock.

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2014:

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	39.5856	$ 25.2617	May 17, 2015	$ 32.8402
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	38.2538	$ 26.1412	May 17, 2015	$ 33.9836
4.50% cumulative convertible	September 2005	$ 100	Any time	2.4468	$ 40.8693	September 15, 2010	$ 53.1301
5.00% cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.7669	$ 36.1415	November 15, 2010	$ 46.9840

(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, 2014, 2013 and 2012:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2014, 2013 and 2012 and shares outstanding as of December 31, 2014, 2013 and 2012	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, payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

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

Accumulated Other Comprehensive Income (Loss)

For the years ended December 31, 2014 and 2013, changes in accumulated other comprehensive income (loss) by component, net of tax, are detailed below.

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
		($ in millions)	
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)
Balance, December 31, 2012	$ (189)	$ 7	$ (182)
Other comprehensive income before reclassifications	2	(6)	(4)
Amounts reclassified from accumulated other comprehensive income	20	4	24
Net other comprehensive income	22	(2)	20
Balance, December 31, 2013	$ (167)	$ 5	$ (162)

For the years ended December 31, 2014 and 2013, 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	Year Ended December 31, 2014
		($ in millions)
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
Year Ended December 31, 2013:		
Net losses on cash flow hedges:		
Commodity contracts	Oil, natural gas and NGL revenues	$ 20
Investments:		
Impairment of investment	Losses on investments	6
Sale of investment	Net gain on sale of investment	(2)
Total reclassifications for the period, net of tax		$ 24

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (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. CHK C-T is an unrestricted subsidiary under our revolving credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including indebtedness under our indentures. 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. Subject to customary minority interest protections afforded the investors by the terms of the CHK C-T limited liability company agreement (the CHK C-T LLC Agreement), as the holder of all the common shares and the sole managing member of CHK C-T, we maintain voting and managerial control of CHK C-T and therefore include it in our consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $225 million to the ORRI obligation and $1.025 billion to the preferred shares based on estimates of fair values. The remaining ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our consolidated balance sheets. Pursuant to the CHK C-T LLC Agreement, CHK C-T is required to retain an amount of cash equal to the next two quarters of preferred dividend payments. The amount reserved, approximately $38 million as of December 31, 2014 and 2013, was reflected as restricted cash on our consolidated balance sheets.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. As the managing member of CHK C-T, we may, at our sole discretion and election at any time after March 31, 2014, distribute certain excess cash of CHK C-T, as determined in accordance with the CHK C-T LLC Agreement and the development agreement, as amended. The optional distribution of excess cash is allocated 75% to the preferred shares (which is applied toward redemption of the preferred shares) and 25% to the common shares; provided, however, that in certain circumstances, as set forth in the CHK C-T L.L.C. Agreement and the development agreement, as amended, the optional distribution would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, in accordance with the CHK C-T LLC Agreement, cause CHK C-T to redeem all or a portion of the CHK C-T preferred shares for cash. The preferred shares may be redeemed at a valuation equal to the greater of a 9% internal rate of return or a return on investment of 1.35x, in each case inclusive of dividends paid through redemption at the rate of 6% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to March 31, 2019, the optional redemption valuation will increase to provide a 15% internal rate of return to the investors. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of December 31, 2014 and 2013, the redemption price and the liquidation preference were approximately $1,185 and $1,245, respectively, per preferred share.

We initially committed to drill and complete, for the benefit of CHK C-T in the area of mutual interest, a minimum of 37.5 net wells per six-month period through 2013, inclusive of wells drilled in 2012, and 25 net wells per six-month period in 2014 through 2016, up to a minimum cumulative total of 300 net wells. In April 2014, the drilling commitment was amended to require us to drill and complete a minimum cumulative total of (i) 162.5 net wells by June 30, 2014 and (ii) 175 net wells by December 31, 2014. In January 2015, the drilling commitment was suspended. We are not required or allowed to drill any wells with respect to the CHK C-T properties unless we receive written notice from the owners of a majority of the preferred shares electing to lift the drilling prohibition. If we receive written notice at least 45 days prior to June 30, 2015, we will be required to drill and complete a minimum cumulative total of 225 net wells by June 30, 2016, and thereafter the minimum cumulative total will be increased by 25 net wells in each of the subsequent six-month periods ending December 31, 2017. If notice is not received by that time, future drilling commitment dates will be extended, as provided in the January 2015 amendment to the drilling commitment. If we fail to meet the then-current cumulative drilling commitment in any six-month period, any optional cash distributions will be distributed 100% to the investors. If we fail to meet the then-current cumulative drilling commitment in two consecutive six-month periods, the then-applicable internal rate of return to investors at redemption will increase by 3% per annum. In addition, if we fail to meet the then-current cumulative drilling commitment in four consecutive six-month periods, the then-applicable internal rate of return to investors at redemption will be increased by an additional 3% per annum. Any increase in the internal rate of return would be effective only until the end of the first succeeding six-month period in which we have met our then-current cumulative drilling commitment. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. Under the development agreement, approximately 17, 77 and 84 qualified net wells were added in 2014, 2013 and 2012, respectively. Through December 31, 2014, we had met all current drilling commitments associated with the CHK C-T transaction.

The CHK C-T investors' right to receive, proportionately, a 3.75% ORRI in the contributed wells and up to 1,000 future net wells on our contributed leasehold is subject to an increase to 5% 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 from 2012 through the first quarter of 2025. However, in no event are we required to deliver to investors more than a total ORRI of 3.75% in existing wells and 1,000 future net wells. If at any time CHK C-T holds fewer net acres than would enable us to drill all then-remaining net wells on 160-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. CHK C-T retains 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 867 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our oil and natural gas properties. We had met our ORRI conveyance commitment as of December 31, 2013, but we did not meet the 2014 ORRI conveyance commitment as of December 31, 2014.

As of December 31, 2014 and 2013, $1.015 billion of noncontrolling interests on our consolidated balance sheets were attributable to CHK C-T. For 2014, 2013 and 2012, income of $75 million, $75 million and $57 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 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 is 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 from 2012 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. 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 will be reduced accordingly. We met the 2013 ORRI conveyance commitment as of December 31, 2013 and met the 2014 ORRI conveyance commitment as of December 31, 2014 associated with the CHK Utica transaction.

As of December 31, 2014 and 2013, $0 and $807 million, respectively, of noncontrolling interests on our consolidated balance sheets were attributable to CHK Utica. In 2014, 2013 and 2012, income of approximately $43 million, $79 million and $88 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 initial public offering of the Trust, 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 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, or cause to be drilled, 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 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 that may be recovered by the Trust under the lien cannot exceed $263 million initially and will be proportionately reduced as we fulfill our drilling obligation over time. As of December 31, 2014 and 2013, we had drilled or caused to be drilled approximately 102 and 82 development wells, respectively, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $36 million and $79 million, respectively.

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 will be 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 ten quarters of distributions paid. 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 will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. Through December 31, 2014, 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 such 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, 2014, 2013 and 2012, the Trust declared and paid the following distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
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
June 2012 - August 2012	November 29, 2012	$ 0.6300	$ 0.2208
March 2012 - May 2012	August 30, 2012	$ 0.6100	$ 0.4819
December 2011 - February 2012	May 31, 2012	$ 0.6588	$ 0.6588
September 2011 - November 2011	March 1, 2012	$ 0.7277	$ 0.7277

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, 2014 and 2013, $287 million and $314 million, respectively, of noncontrolling interests on our consolidated balance sheets were attributable to the Trust. In 2014, 2013 and 2012, income of approximately $24 million, $20 million and $35 million, respectively, was attributable to the Trust's noncontrolling interests in our consolidated statements of operations. See Note 15 for further discussion of VIEs.

Wireless Seismic, Inc. As of December 31, 2014, we no longer consolidated Wireless Seismic, Inc. (Wireless), a privately owned company engaged in research, development and production of wireless seismic systems and related technology that delivers seismic information obtained from standard geophones in real time to personal computers. Because we no longer have a controlling equity interest in Wireless, our interest is included in investments in our consolidated balance sheet and within other in the table in Note 14.

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 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. As of December 31, 2014, 36 million shares of common stock remained issuable under the 2014 LTIP.

2005 Long Term Incentive Plan. Chesapeake's 2005 LTIP, which terminated upon shareholder approval of the 2014 LTIP on June 13, 2014, provided for the issuance of restricted stock, stock options and PSUs to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock available for awards under the plan was limited to 59,300,000 shares. The maximum period for exercise of an option or SAR was not more than ten years from the date of grant, and the exercise price was not less than the fair market value of the shares underlying the option or SAR on the date of grant. Awards granted under the plan became vested at specified dates or upon the satisfaction of certain performance or other criteria determined by a committee of the Board of Directors. The plan was approved by our shareholders. We issued 48,083, 147,108 and 170,151 shares of restricted stock to non-employee directors under the 2005 LTIP in 2014, 2013 and 2012, respectively. We issued options to purchase 993,730, 5.3 million and no shares of common stock to employees and consultants under the 2005 LTIP in 2014, 2013 and 2012, respectively. Additionally, we issued 1.3 million, 2.5 million and 5.0 million shares of restricted stock, net of forfeitures, to employees and consultants under the 2005 LTIP in 2014, 2013 and 2012, respectively.

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, 20,000 and 30,000 shares of common stock to newly appointed non-employee directors under the 2003 Non-Employee Director Plan in 2014, 2013 and 2012, respectively. As of December 31, 2014, there were 120,000 shares remaining available for issuance under the 2003 Non-Employee Director Plan.

Equity-Classified Awards

Restricted Stock. We grant restricted stock to employees and non-employee directors. Restricted stock vests over a minimum of three years and the holder receives dividends on unvested shares. A summary of the changes in unvested restricted stock during 2014, 2013 and 2012 is presented below.

	Shares of Unvested Restricted Stock (in thousands)	Weighted Average Grant Date Fair Value
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
Unvested restricted stock as of January 1, 2012	19,544	$ 26.97
Granted	9,480	$ 21.13
Vested	(8,620)	$ 28.08
Forfeited	(1,505)	$ 24.57
Unvested restricted stock as of December 31, 2012	18,899	$ 23.72

The aggregate intrinsic value of restricted stock that vested during 2014 was approximately $130 million based on the stock price at the time of vesting.

As of December 31, 2014, there was approximately $135 million of total unrecognized compensation expense related to unvested restricted stock. The expense is expected to be recognized over a weighted average period of approximately 2.02 years.

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 common stock at the date of vesting and the date of grant. During 2014, we recognized an excess tax benefit related to restricted stock of $12 million. During 2013 and 2012, we recognized reductions in tax benefits related to restricted stock of $14 million and $32 million, respectively. Each adjustment was recorded to additional paid-in capital and deferred income taxes.

Stock Options. In 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 to certain officers of stock options 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 generally expire 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 current 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 2014:

Expected option life - years	5.9
Volatility	48.63%
Risk-free interest rate	1.93%
Dividend yield	1.33%

The following table provides information related to stock option activity for 2014, 2013 and 2012:

	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, 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
Outstanding at January 1, 2012	1,051	$ 9.84	1.41	$ 13
Exercised	(570)	$ 7.45		$ 7
Outstanding and exercisable at December 31, 2012	481	$ 12.69	0.96	$ 2

(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, 2014, there was $11 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 2.02 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 2014, 2013 and 2012, we recognized excess tax benefits related to stock options of $3 million, $1 million and $2 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, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
	($ in millions)		
General and administrative expenses	$ 46	$ 60	$ 71
Oil and natural gas properties	29	52	71
Oil, natural gas and NGL production expenses	18	21	24
Marketing, gathering and compression expenses	6	7	15
Oilfield services expenses	5	10	10
Total	$ 104	$ 150	$ 191

Liability-Classified Awards

Performance Share Units. In 2012, 2013 and 2014, we granted PSUs to senior management that settle in cash at the end of their respective performance periods and vest ratably over their respective terms. The 2012 awards were granted in one-, two- and three-year tranches and are settled in cash on the first, second and third anniversary dates of the awards, and the 2013 and 2014 awards 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, the achievement of operational performance goals such as production and proved reserve growth.

For PSUs granted in 2012, each of the TSR and operational payout components can range from 0% to 125% resulting in a maximum total payout of 250%. For PSUs granted in 2013, the TSR component can range from 0% to 125% and each of the two operational components can range from 0% to 62.5%; however, the maximum total payout is capped at 200%. For PSUs granted in 2014, the TSR component can range from 0% to 200%, with no operational components. For the 2013 and 2014 PSUs, the payout percentage is capped at 100% if the Company’s absolute TSR is less than zero. Compensation expense associated with the PSU grants is recognized over the service period. The number of units settled is dependent upon the Company’s estimates of the underlying performance measures. For the 2014 awards, 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	41.37%
Risk-free interest rate	0.76%
Dividend yield for value of awards	1.36%

The following table presents a summary of our PSU awards:

	Units	Fair Value as of Grant Date	Fair Value[(a)]	Liability for Vested Amount
			($ in millions)	
2012 Awards [(b)]				
Payable 2015	884,507	$ 23	$ 12	$ 12
2013 Awards				
Payable 2016	1,701,941	$ 35	$ 42	$ 39
2014 Awards				
Payable 2017	609,637	$ 16	$ 10	$ 7

(a) As of December 31, 2014.

(b) In 2014 and 2013, we paid $11 million and $2 million, respectively, related to 2012 PSU awards.

PSU Compensation. We recognized the following compensation costs related to PSUs for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31, 2014	2013	2012
		($ in millions)	
General and administrative expenses	$ (4)	$ 34	$ 8
Oil and natural gas properties	3	9	4
Oil, natural gas and NGL production expenses	—	2	1
Marketing, gathering and compression expenses	—	2	1
Oilfield services expenses	—	1	—
Total	$ (1)	$ 48	$ 14

Effect of the Spin-off on Share-Based Compensation

The employee matters agreement entered into in connection with the 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. The Company contributed $61 million, $81 million and $91 million to the 401(k) Plan in 2014, 2013 and 2012, respectively. Beginning January 1, 2015, Chesapeake will match employee contributions in cash.

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 the 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 has 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 $7 million, $14 million and $16 million to the DC Plan during 2014, 2013 and 2012, respectively, to fund the match. In addition, in 2012 the Board of Directors adopted a deferred compensation plan for non-employee directors (Director DC Plan). The Company's non-employee directors are able to defer up to 100% of director cash compensation into the Director DC Plan and invest in Chesapeake common stock, but the plan does not provide for Company matching contributions.

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, 2014, 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 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 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, 2014 and 2013, 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.
- *Collars:* These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike prices, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the call option. This eliminates the counterparty's downside exposure below the second put option strike price.
- *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.
- *Call Swaptions:* Chesapeake sells call swaptions in exchange for a premium that allows a counterparty, on a specific date, to enter into a fixed-price swap for a certain period of time.
- *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, 2014 and 2013 are provided below.

	December 31, 2014		December 31, 2013	
	Volume	Fair Value	Volume	Fair Value
		($ in millions)		($ in millions)
Oil (mmbbl):				
Fixed-price swaps	12.5	471	25.3	(50)
Three-way collars	4.4	40	—	—
Call options	35.8	(89)	42.5	(265)
Basis protection swaps	—	—	0.4	1
Total oil	52.7	422	68.2	(314)
Natural gas (tbtu):				
Fixed-price swaps	275	$ 281	448	$ (23)
Three-way collars	207	165	288	(7)
Call options	193	(170)	193	(210)
Call swaptions	—	—	12	—
Basis protection swaps	60	23	68	3
Total natural gas	735	299	1,009	(237)
Total estimated fair value		$ 721		$ (551)

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, 2014 and 2013, 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 bank credit facility borrowings.

The notional amount of our interest rate derivatives, associated with our long-term debt, as of December 31, 2014 and 2013 was $850 million and $2.250 billion, respectively. The estimated fair value of our interest rate derivative liabilities as of December 31, 2014 and 2013 was $17 million and $98 million, respectively.

We have terminated certain fair value hedges related to 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 $10 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 that may result from the €344 million principal amount of our euro-denominated senior notes. 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. Under the terms of the cross currency swaps we currently hold, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we will pay the counterparties $459 million. 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 sheet as a liability of $53 million and an asset of $2 million as of December 31, 2014 and 2013, respectively. The euro-denominated debt in long-term debt has been adjusted to $416 million as of December 31, 2014 using an exchange rate of $1.2098 to €1.00.

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, 2014 and 2013 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, 2014			
Commodity Contracts			
Short-term derivative asset	$ 974	$ (95)	$ 879
Long-term derivative asset	16	(10)	6
Short-term derivative liability	(105)	95	(10)
Long-term derivative liability	(163)	10	(153)
Total commodity contracts	722	—	722
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)
Total Derivatives	$ 652	$ —	$ 652
As of December 31, 2013			
Commodity Contracts			
Short-term derivative asset	$ 29	$ (29)	$ —
Long-term derivative asset	11	(9)	2
Short-term derivative liability	(231)	29	(202)
Long-term derivative liability	(362)	9	(353)
Total commodity contracts	(553)	—	(553)
Interest Rate Contracts			
Short-term derivative liability	(6)	—	(6)
Long-term derivative liability	(92)	—	(92)
Total interest rate contracts	(98)	—	(98)
Foreign Currency Contracts[(a)]			
Long-term derivative asset	2	—	2
Total foreign currency contracts	2	—	2
Total Derivatives	$ (649)	$ —	$ (649)

(a) Designated as cash flow hedging instruments.

As of December 31, 2014 and 2013, 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 sales for the years ended December 31, 2014, 2013 and 2012 are presented below.

	Years Ended December 31,		
	2014	2013	2012
		($ in millions)	
Oil, natural gas and NGL sales	$ 7,162	$ 6,923	$ 5,359
Gains on undesignated oil and natural gas derivatives	1,055	443	857
Gains (losses) on terminated cash flow hedges	(37)	(314)	62
Total oil, natural gas and NGL sales	$ 8,180	$ 7,052	$ 6,278

The components of interest expense for the years ended December 31, 2014, 2013 and 2012 are presented below.

	Years Ended December 31,		
	2014	2013	2012
		($ in millions)	
Interest expense on senior notes	$ 704	$ 740	$ 732
Interest expense on term loans	36	116	173
Amortization of loan discount, issuance costs and other	42	91	89
Interest expense on credit facilities	28	38	70
Gains on terminated fair value hedges	(3)	(5)	(8)
(Gains) losses on undesignated interest rate derivatives	(81)	63	1
Capitalized interest	(637)	(816)	(980)
Total interest expense	$ 89	$ 227	$ 77

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,					
	2014		2013		2012	
	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
			($ in millions)			
Balance, beginning of period	$ (269)	$ (167)	$ (304)	$ (189)	$ (287)	$ (178)
Net change in fair value	1	1	3	2	10	6
Gains (losses) reclassified to income	37	23	32	20	(27)	(17)
Balance, end of period	$ (231)	$ (143)	$ (269)	$ (167)	$ (304)	$ (189)

Approximately $136 million of the $143 million of accumulated other comprehensive loss as of December 31, 2014 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. These amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of December 31, 2014, we expect to transfer approximately $23 million of net loss included in accumulated other comprehensive income to net income during the next 12 months. The remaining amounts will be transferred by December 31, 2022.

Credit Risk Considerations

Over-the-counter traded derivative instruments expose us to our counterparties' credit risk. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of December 31, 2014, our oil, natural gas and interest rate derivative instruments were spread among 18 counterparties.

Hedging Facility

Our secured commodity hedging facility with 17 counterparties provides approximately 1.031 bboe of hedging capacity for oil, natural gas and NGL price derivatives and 1.031 bboe for basis derivatives with an aggregate mark-to-market capacity of $16.5 billion. The facility is secured by proved reserves, the value of which must cover 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. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain requirements are met including maintaining specified collateral coverage ratios as well as maintaining credit ratings with either of the designated rating agencies at or above current levels. The counterparties' obligations under the facility must be secured by cash or short-term U.S. treasury instruments to the extent that any mark-to-market amounts they owe Chesapeake exceed defined thresholds. As of December 31, 2014, we had hedged under the facility 164 mmboe of our future production with price derivatives and 10 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, 2014 and 2013:

	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, 2014				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 785	$ 205	$ 990
Commodity liabilities	—	(9)	(259)	(268)
Interest rate liabilities	—	(17)	—	(17)
Foreign currency liabilities	—	(53)	—	(53)
Total derivatives	$ —	$ 706	$ (54)	$ 652
As of December 31, 2013				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 25	$ 15	$ 40
Commodity liabilities	—	(100)	(493)	(593)
Interest rate liabilities	—	(98)	—	(98)
Foreign currency assets	—	2	—	2
Total derivatives	$ —	$ (171)	$ (478)	$ (649)

A summary of the changes in the fair values of Chesapeake's financial assets (liabilities) classified as Level 3 during 2014 and 2013 is presented below.

	Derivatives	
	Commodity	Interest Rate
	($ in millions)	
Beginning Balance as of January 1, 2014	$ (478)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	292	—
Total purchases, issuances, sales and settlements:		
Settlements	136	—
Transfers[(b)]	(4)	—
Ending Balance as of December 31, 2014	$ (54)	$ —
Beginning Balance as of January 1, 2013	$ (1,016)	$ —
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	410	(1)
Total purchases, issuances, sales and settlements:		
Sales	—	1
Settlements	128	—
Ending Balance as of December 31, 2013	$ (478)	$ —

(a)

	Oil, Natural Gas and NGL Sales		Interest Expense	
	2014	2013	2014	2013
	($ in millions)			
Total gains (losses) included in earnings for the period	$ 292	$ 410	$ —	$ (1)
Change in unrealized gains (losses) related to assets still held at reporting date	$ 262	$ 382	$ —	$ —

(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 (decrease) in the forward prices and volatility of oil and natural gas prices decreases (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, 2014:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value December 31, 2014[(a)]
				($ in millions)
Oil trades	Oil price volatility curves	27.33% - 43.56%	34.09%	$ (49)
Natural gas trades	Natural gas price volatility curves	18.71% - 63.70%	34.38%	$ (5)

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

12. Oil and Natural Gas Property Transactions

Under full cost accounting rules, we have accounted for the sale of oil and natural gas properties as an adjustment to capitalized costs, with no recognition of gain or loss as the sales have not involved a significant change in proved reserves or significantly altered the relationship between costs and proved reserves.

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 is currently 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 are currently designated operator. In addition to the exchange, we paid RKI approximately $450 million in cash.

We sold noncore leasehold interests in the Marcellus Shale to a subsidiary of Rice Energy Inc. for net proceeds of approximately $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 approximately $133 million. All commitments related to VPP #5 were also transferred. See *Volumetric Production Payments* below.

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

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

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.

2012 Transactions

We sold the vast majority of our Permian Basin assets, representing approximately 6% of our total proved reserves as of June 30, 2012, in three separate transactions for total net cash proceeds of approximately $3.091 billion. Following the closing, we received $466 million of additional consideration that was withheld subject to certain title, environmental and other standard contingencies. Of the total proceeds, we allocated approximately $42 million to our Permian Basin midstream and other fixed assets. The remaining proceeds were allocated to our Permian Basin oil and natural gas properties.

We sold approximately 40,000 net acres of noncore leasehold in the Chitwood Knox play in Oklahoma for approximately $540 million in cash.

We sold approximately 72,000 net acres of noncore leasehold in the Utica Shale play in Ohio to affiliates of EnerVest, Ltd. for approximately $358 million in cash.

We sold approximately 60,000 net acres of leasehold in the Texoma Woodford play in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation, for net proceeds of approximately $572 million.

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 Copper & Gold (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, 2014, we had utilized all drilling carries from our joint venture partners except for Total's remaining $51 million commitment to pay 60% of our drilling and completion costs for wells drilled in the Utica Shale play. We fully expect to use this drilling carry commitment prior to its expiration in December 2018.

In 2014, 2013 and 2012, our drilling and completion costs included the benefit of approximately $679 million, $884 million and $784 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, including $90 million we received for closing adjustments and $71 million placed in escrow with respect to certain post-closing adjustments. As of December 31, 2014, we had received $64 million of the $71 million held in escrow. There was no drilling and completion carry associated with this transaction.

In addition, in 2014, 2013 and 2012, we sold interests in additional leasehold we acquired in the Marcellus, Barnett, Utica, Eagle Ford and Mid-Continent plays to our joint venture partners for approximately $33 million, $58 million and $272 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 have novated hedges to each of the respective VPP buyers and these hedges 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, 2014, 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
8	September 2010	Barnett Shale	1,150	—	390	—	390
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
			$ 5,481	5.2	1,105	14.0	1,220

The volumes produced on behalf of our VPP buyers during 2014, 2013 and 2012 were as follows:

	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[(a)]	23.1	4.2	—	4.3
5[(a)]	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

	Year Ended December 31, 2012			
VPP #	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)
10	727.0	18.1	1,729.1	32.8
9	249.3	18.4	643.6	23.7
8	—	79.7	—	79.7
7[(b)]	490.3	0.4	—	3.4
6	24.0	5.3	—	5.5
5	27.4	8.8	—	9.0
4	62.8	11.7	—	12.2
3	—	9.3	—	9.3
2	—	11.4	—	11.3
1	—	15.3	—	15.3
	1,580.8	178.4	2,372.7	202.2

(a) In 2014, we divested the properties associated with VPP #5 and VPP #6.

(b) In 2012, to facilitate the sales process associated with our Permian Basin divestiture packages, we purchased the remaining reserves from our Permian Basin VPP (VPP #7). The reserves purchased were subsequently sold to the buyers of our Permian Basin assets.

The volumes remaining to be delivered on behalf of our VPP buyers as of December 31, 2014 were as follows:

		Volume Remaining as of December 31, 2014			
VPP #	Term Remaining	Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
10	86	1.3	38.0	4.7	74.0
9	74	0.8	73.2	1.9	89.9
8	8	—	36.6	—	36.6
4	24	0.1	15.3	—	15.8
3	55	—	23.9	—	23.9
2	52	—	13.8	—	13.8
1	96	—	91.5	—	91.5
		2.2	292.3	6.6	345.5

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 an independent, publicly traded company called SSE. 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 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 a corporation named Seventy Seven Energy Inc.
- 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 described below, 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.
- 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, 2014, the aggregate undiscounted minimum future payments under these drilling agreements were approximately $410 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. See Note 18 for further details regarding these charges.

14. Investments

A summary of our investments, including our approximate ownership percentage and carrying value as of December 31, 2014 and 2013, is presented below.

	Accounting Method	Approximate Ownership % December 31, 2014	Approximate Ownership % December 31, 2013	Carrying Value December 31, 2014	Carrying Value December 31, 2013
				($ in millions)	
FTS International, Inc.	Equity	30%	30%	$ 116	$ 138
Sundrop Fuels, Inc.	Equity	56%	56%	130	135
Chaparral Energy, Inc.	Equity	—%	20%	—	143
Other	—	—%	—%	19	61
Total investments				$ 265	$ 477

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 2014, we recorded negative equity method and other adjustments of $32 million for our share of FTS's net loss and recorded an accretion adjustment of $10 million related to the excess of our underlying equity in net assets of FTS over our carrying value.

As of December 31, 2014, the carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $44 million, of which $14 million was attributed to non-depreciable assets. The value attributed to depreciable assets is being accreted over the estimated useful lives of the underlying assets.

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 2014, we recorded a $21 million charge related to our share of Sundrop's net loss and $16 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 $78 million as of December 31, 2014 and will be amortized over the life of the plant once it is placed into service.

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.

Chesapeake Midstream Partners, L.P. In 2012, we sold all of our common and subordinated units representing limited partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P., and all of our limited liability company interests in the sole member of its general partner to funds affiliated with Global Infrastructure Partners for cash proceeds of $2.0 billion. We recorded a $1.032 billion gain associated with the transaction.

Glass Mountain Pipeline, LLC. In 2012, our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.L.C. (CMD), entered into an agreement with two other parties to form Glass Mountain Pipeline, LLC to construct a 210 mile pipeline in western and north central Oklahoma in which CMD had a 50% ownership interest. In 2012, CMD sold its interest for $99 million and recorded a gain of $62 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 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 could potentially 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, 2014, $1 million of cash and cash equivalents, $16 million of short-term derivative assets, $488 million of proved oil and natural gas properties, $251 million of accumulated depreciation, depletion and amortization and $15 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 $9 million as of December 31, 2014.

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, 2014	December 31, 2013	Estimated Useful Life
	($ in millions)		(in years)
Buildings and improvements	$ 1,242	$ 1,433	10 - 39
Natural gas compressors	551	368	3 - 20
Land	296	212	—
Gathering systems and treating plants	218	292	20
Oilfield services equipment	—	2,192	3 - 15
Other	776	898	2 - 20
Total other property and equipment, at cost	3,083	5,395	
Less: accumulated depreciation	(804)	(1,584)	
Total other property and equipment, net	$ 2,279	$ 3,811	

Net Gains 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, 2014, 2013 and 2012 is as follows:

	Years Ended December 31, 2014	2013	2012
		($ in millions)	
Natural gas compressors	$ (195)	$ —	$ —
Gathering systems and treating plants	8	(326)	(286)
Oilfield services equipment	(7)	2	10
Buildings and land	(2)	27	7
Other	(3)	(5)	2
Total net gains on sales of fixed assets	$ (199)	$ (302)	$ (267)

Natural Gas Compressors. In 2014, as part of a divestiture of noncore oil and natural gas properties in South Texas, we sold 61 compressors and related equipment to Hilcorp Energy Company for $19 million. We recorded a $6 million gain associated with the compressors sold. Also in 2014, we sold 499 compressors and related equipment to Exterran Partners, L.P. for approximately $495 million. We recorded a $161 million gain associated with the compressors sold. In 2014, we also sold 102 compressors and related equipment to Access Midstream Partners, L.P. (ACMP) for proceeds of approximately $159 million. We recorded a $24 million gain associated with the transaction.

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.

In 2012, CMD sold its wholly owned subsidiary, CMO, which held a majority of our midstream business, to ACMP for total consideration of $2.16 billion in cash. In connection with the sale, Chesapeake entered into new long-term agreements in which ACMP agreed to perform certain natural gas gathering and related services for us within specified acreage dedication areas in exchange for (i) cost-of-service based fees redetermined annually beginning January 2014 in the Niobrara and Marcellus Shale plays, (ii) cost-of-service based fees redetermined annually beginning October 2013 for the wet gas gathering systems and January 2014 for the dry gas gathering systems in the Utica Shale play, (iii) tiered fees based on volumes delivered relative to scheduled volumes through 2015 and thereafter cost-of-service based fees redetermined annually in the Eagle Ford Shale play, and (iv) annual minimum volume commitments and a fixed fee per mmbtu of natural gas gathered, subject to an annual 2.5% rate escalation, through 2017 and thereafter tiered fees based on volumes delivered relative to scheduled volumes in the Haynesville Shale play. We recorded a $289 million gain associated with this transaction.

In 2012, we sold our oil gathering business and related assets in the Eagle Ford Shale to Plains Pipeline, L.P. for cash proceeds of approximately $115 million. Subsequent to December 31, 2012, we received an additional $10 million of proceeds upon satisfaction of a certain closing contingency. We recorded a $3 million gain associated with this transaction. In connection with the sale, we entered into new gathering and transportation agreements covering acreage dedication areas.

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.

Buildings and Land. The 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 our Oklahoma City and Barnett Shale operating area.

Assets Held for Sale

In 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. In addition, as of December 31, 2014, we were continuing to pursue the sale of land located in the Fort Worth, Texas area. Land and buildings are recorded within our other segment. These Oklahoma City and Fort Worth 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, 2014. 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. A summary of the assets held for sale on our consolidated balance sheets as of December 31, 2014 and 2013 is detailed below.

	December 31,	
	2014	2013
	($ in millions)	
Buildings and land, net of accumulated depreciation	$ 93	$ 405
Compressors, net of accumulated depreciation	—	285
Oilfield services equipment, net of accumulated depreciation	—	29
Gathering systems and treating plants, net of accumulated depreciation	—	11
Property and equipment held for sale, net	$ 93	$ 730

In 2014, management determined that certain properties in the Fort Worth area of the Barnett Shale, previously classified as held for sale as of December 31, 2013, would be reclassified as held for use. As of December 31, 2013, management's development plan for the Barnett Shale did not contemplate the need for the underlying properties (for pad drilling in certain urban locations around Fort Worth) and the properties were marketed for sale. Management modified its development plan and consequently these properties no longer met the criteria to be classified as held for sale. The properties were measured at the lesser of their fair value at the date of the decision not to sell or their carrying amount before being classified as held for sale. During 2014, we reclassified $120 million of these properties to held for use classification. There was no impact to the statement of operations related to this reclassification.

During 2014, we sold compressors previously classified as held for sale to Hilcorp Energy Company and Exterran Partners, L.P. The oilfield services equipment was included in the spin-off of our oilfield services business. See Note 13 for further discussion of the spin-off.

17. Impairments

Impairments of Oil and Natural Gas Properties

Our oil and natural gas properties are subject to quarterly full cost ceiling tests. As of September 30, 2012, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in an impairment in the carrying value of oil and natural gas properties of $3.315 billion. Cash flow hedges as of September 30, 2012, which related to future periods, increased the ceiling test impairment by $279 million. We were not required to record impairments of oil and natural gas properties for any other quarter in 2012 or for any quarters in 2013 or 2014. Based on the decline in oil and natural gas prices in the second half of 2014 and into 2015, we expect to have a material write-down of the carrying value of our oil and natural gas properties in the 2015 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.

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, 2014, 2013 and 2012 is as follows:

	Years Ended December 31,		
	2014	2013	2012
	($ in millions)		
Natural gas compressors	$ 11	$ —	$ —
Gathering systems and treating plants	13	22	6
Oilfield services equipment	23	71	60
Buildings and land	18	366	248
Other	23	87	26
Total impairments of fixed assets and other	$ 88	$ 546	$ 340

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. We recognized an impairment loss of approximately $15 million related to leasehold improvements associated with these assets. In 2013, we purchased 23 leased rigs (two of which were classified as held for sale assets as of December 31, 2013) 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 that qualified as held for sale during 2013 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. In 2012, we purchased 25 leased rigs from various lessors for an aggregate purchase price of $36 million and paid approximately $25 million in early lease termination costs, which is included in impairments of fixed assets and other in the consolidated statement of operations. In addition, in 2012, we recognized $26 million of impairment losses on certain of our drilling rigs that we expected would have insufficient cash flow to recover carrying values because of a change in business climate resulting from depressed natural gas prices. In 2012, we also recognized $9 million of impairment losses primarily related to drill pipe and other oilfield services equipment.

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. In addition, in 2012, we recognized $248 million of impairment losses associated with an office building and surface land located in our Barnett Shale operating area. The change in business climate in the Barnett Shale in 2012, evidenced by our significant reduction in Barnett Shale operations and depressed natural gas prices, required us to test these long-lived assets for recoverability.

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 2014, 2013 and 2012 are included in our other segment.

Other. 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 2014, we revised our estimate of our net acreage shortfall as of December 31, 2012 under the terms of our Barnett Shale joint venture agreement with Total and recorded an additional $22 million charge. See Note 4 for additional discussion regarding our net acreage maintenance commitments. In 2013, we recorded approximately $87 million of other charges, including $26 million for the termination of a gas gathering agreement, $28 million for the impairment of certain assets used to promote natural gas demand, $15 million for the termination of a contract drilling agreement with a third party, $2 million related to the estimated 2012 shortfall of our net acreage maintenance commitment with Total in the Barnett Shale and $16 million related to various other assets. In 2012, we recorded a $26 million charge related to the estimated 2012 shortfall of our net acreage maintenance commitment with Total in the Barnett Shale.

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, the values were classified as Level 2 in the fair value hierarchy. Fair value measurements of the buildings and land discussed above were based on prices from orderly sales transactions for comparable properties between market participants, purchase offers we received from third parties and, in certain cases, discounted cash flows. As some 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

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.

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.

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.

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.

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.

Below is a summary of our restructuring and other termination costs for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
		($ in millions)	
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	—	—
Restructuring charges under workforce reduction plan:			
Salary expense	—	20	—
Acceleration of stock-based compensation	—	45	—
Other termination benefits	—	1	—
Total restructuring changes under workforce reduction plan	—	66	—
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)	18	—
Estimated aircraft usage benefits	—	7	—
Total termination benefits provided to Mr. McClendon	(8)	69	—
Termination benefits provided to VSP participants:			
Salary and bonus expense	—	33	1
Acceleration of stock-based compensation	—	29	1
Other termination benefits	—	1	—
Total termination benefits provided to VSP participants	—	63	2
Other termination benefits[(a)]	—	50	5
Total restructuring and other termination costs	$ 7	$ 248	$ 7

(a) Amounts for the year ended December 31, 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.

19. Fair Value Measurements

Recurring Fair Value Measurements

Other Current Assets. Assets related to Company matches of employee contributions to Chesapeake's employee benefit plans 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, 2014 and 2013:

	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, 2014				
Financial Assets (Liabilities):				
Other current assets	$ 57	$ —	$ —	$ 57
Other current liabilities	(58)	—	—	(58)
Total	$ (1)	$ —	$ —	$ (1)
As of December 31, 2013				
Financial Assets (Liabilities):				
Other current assets	$ 80	$ —	$ —	$ 80
Other current liabilities	(82)	—	—	(82)
Total	$ (2)	$ —	$ —	$ (2)

See Note 3 for information regarding fair value of other financial instruments. See Note 11 for information regarding fair value measurement of 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, 2014	Years Ended December 31, 2013
	($ in millions)	
Asset retirement obligations, beginning of period	$ 405	$ 375
Additions	29	20
Revisions[(a)]	101	8
Settlements and disposals	(92)	(20)
Accretion expense	22	22
Asset retirement obligations, end of period	465	405
Less current portion [(b)]	18	—
Asset retirement obligation, long-term	$ 447	$ 405

(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 ExxonMobil Corporation and Plains Marketing, L.P. constituted approximately 12% and 11%, respectively, of our total revenues (before the effects of hedging) for the years ended December 31, 2014 and 2012, respectively. 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, 2014, 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 described in Note 13, 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 $8.565 billion, $7.570 billion and $5.464 billion for the years ended December 31, 2014, 2013 and 2012, 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, $1.309 billion and $1.315 billion for the years ended December 31, 2014, 2013 and 2012, respectively. No income was recognized in our consolidated statements of operations related to oilfield services performed for Chesapeake-operated wells.

The following tables present 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, 2014:						
Revenues	$ 8,180	$ 20,790	$ 1,060	$ 30	$ (9,109)	$ 20,951
Intersegment revenues	—	(8,565)	(544)	—	9,109	—
Total revenues	$ 8,180	$ 12,225	$ 516	$ 30	$ —	$ 20,951
Unrealized gains on commodity derivatives	$ (1,394)	$ —	$ —	$ —	$ —	$ (1,394)
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 gains on sales of fixed assets	$ (2)	$ (187)	$ (8)	$ (2)	$ —	$ (199)
Interest expense	$ (709)	$ (21)	$ (42)	$ 3	$ 680	$ (89)
Earnings (losses) on investments	$ 2	$ —	$ (6)	$ (76)	$ —	$ (80)
Net gain (loss) on sales of investments	$ (6)	$ —	$ —	$ 73	$ —	$ 67
Losses on purchases 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	$ 7,052	$ 17,129	$ 2,188	$ 29	$ (8,892)	$ 17,506
Intersegment revenues	—	(7,570)	(1,309)	(13)	8,892	—
Total revenues	$ 7,052	$ 9,559	$ 879	$ 16	$ —	$ 17,506
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 (gains) losses on sales of fixed assets	$ 2	$ (329)	$ (1)	$ 26	$ —	$ (302)
Interest expense	$ (918)	$ (24)	$ (82)	$ (74)	$ 871	$ (227)
Earnings (losses) on investments	$ 3	$ —	$ (1)	$ (229)	$ 1	$ (226)
Net gain (loss) on sales of investments	$ —	$ —	$ —	$ (7)	$ —	$ (7)
Losses on purchases 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

	Exploration and Production	Marketing, Gathering and Compression	Former Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Year Ended December 31, 2012:						
Revenues	$ 6,278	$ 10,895	$ 1,917	$ 21	$ (6,795)	$ 12,316
Intersegment revenues	—	(5,464)	(1,315)	(16)	6,795	—
Total revenues	$ 6,278	$ 5,431	$ 602	$ 5	$ —	$ 12,316
Unrealized losses on commodity derivatives	$ (561)	$ —	$ —	$ —	$ —	$ (561)
Oil, natural gas, NGL and other depreciation, depletion and amortization	$ 2,624	$ 54	$ 232	$ 46	$ (145)	$ 2,811
Impairment of oil and natural gas properties	$ 3,315	$ —	$ —	$ —	$ —	$ 3,315
Impairments of fixed assets and other	$ 28	$ 6	$ 60	$ 246	$ —	$ 340
Net (gains) losses on sales of fixed assets	$ 14	$ (298)	$ 10	$ 7	$ —	$ (267)
Interest expense	$ (47)	$ (20)	$ (76)	$ (364)	$ 430	$ (77)
Earnings (losses) on investments	$ —	$ 49	$ —	$ (152)	$ —	$ (103)
Net gain (loss) on sales of investments	$ (2)	$ 1,094	$ —	$ —	$ —	$ 1,092
Losses on purchases of debt	$ (200)	$ —	$ —	$ —	$ —	$ (200)
Income (Loss) Before Income Taxes	$ (1,798)	$ 1,665	$ 112	$ (478)	$ (475)	$ (974)
Total Assets	$ 37,004	$ 2,291	$ 2,115	$ 2,529	$ (2,328)	$ 41,611
Capital Expenditures	$ 12,044	$ 852	$ 658	$ 554	$ —	$ 14,108

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, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012. 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, 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	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 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	$ 792	$ 5,084	$ 68	$ (81)	$ 5,863
Intercompany payable, net	—	24,937	—	(24,937)	—
Total Current Liabilities	792	30,021	68	(25,018)	5,863
LONG-TERM LIABILITIES:					
Long-term debt, net	11,154	—	—	—	11,154
Deferred income tax liabilities	—	3,751	234	200	4,185
Other long-term liabilities	112	1,090	142	—	1,344
Total Long-Term Liabilities	11,266	4,841	376	200	16,683
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 BALANCE SHEET
YEAR ENDED DECEMBER 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 799	$ 8	$ 38	$ (8)	$ 837
Restricted cash	—	37	38	—	75
Other	103	2,465	524	(348)	2,744
Intercompany receivable, net	25,549	—	860	(26,409)	—
Total Current Assets	26,451	2,510	1,460	(26,765)	3,656
PROPERTY AND EQUIPMENT:					
Oil and natural gas properties, at cost based on full cost accounting, net	—	30,933	1,471	189	32,593
Other property and equipment, net	—	2,360	1,452	(1)	3,811
Property and equipment held for sale, net	—	701	29	—	730
Total Property and Equipment, Net	—	33,994	2,952	188	37,134
LONG-TERM ASSETS:					
Other assets	111	1,161	96	(376)	992
Investments in subsidiaries and intercompany advances	2,169	(209)	—	(1,960)	—
TOTAL ASSETS	$ 28,731	$ 37,456	$ 4,508	$ (28,913)	$ 41,782
CURRENT LIABILITIES:					
Current liabilities	$ 300	$ 5,262	$ 309	$ (356)	$ 5,515
Intercompany payable, net	—	26,409	—	(26,409)	—
Total Current Liabilities	300	31,671	309	(26,765)	5,515
LONG-TERM LIABILITIES:					
Long-term debt, net	11,831	—	1,055	—	12,886
Deferred income tax liabilities	209	2,338	773	87	3,407
Other long-term liabilities	396	1,278	504	(344)	1,834
Total Long-Term Liabilities	12,436	3,616	2,332	(257)	18,127
EQUITY:					
Chesapeake stockholders’ equity	15,995	2,169	1,867	(4,036)	15,995
Noncontrolling interests	—	—	—	2,145	2,145
Total Equity	15,995	2,169	1,867	(1,891)	18,140
TOTAL LIABILITIES AND EQUITY	$ 28,731	$ 37,456	$ 4,508	$ (28,913)	$ 41,782

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	$ —	$ 7,765	$ 418	$ (3)	$ 8,180
Marketing, gathering and compression	—	12,220	5	—	12,225
Oilfield services	—	41	983	(478)	546
Total Revenues	—	20,026	1,406	(481)	20,951
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	1,166	42	—	1,208
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	16,638	1,542	(806)	17,474
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)	(5)	2	(80)
Net gain on sales of investments	—	67	—	—	67
Losses on purchases 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 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	$ —	$ 6,439	$ 553	$ 60	$ 7,052
Marketing, gathering and compression	—	9,547	12	—	9,559
Oilfield services	—	221	1,836	(1,162)	895
Total Revenues	—	16,207	2,401	(1,102)	17,506
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	1,112	47	—	1,159
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	—	14,277	2,556	(1,396)	15,437
INCOME (LOSS) FROM OPERATIONS	—	1,930	(155)	294	2,069
OTHER INCOME (EXPENSE):					
Interest expense	(921)	(4)	(85)	783	(227)
Losses on investments	—	(225)	(1)	—	(226)
Net loss on sales of investments	—	(7)	—	—	(7)
Losses on purchases of debt	(70)	(123)	—	—	(193)
Other income	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	370	(87)	(870)	548
NET INCOME (LOSS)	724	215	(141)	96	894
Net income attributable to noncontrolling interests	—	—	—	(170)	(170)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	724	215	(141)	(74)	724
Other comprehensive income (loss)	3	19	(2)	—	20
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ 727	$ 234	$ (143)	$ (74)	$ 744

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil, natural gas and NGL	$ —	$ 5,920	$ 351	$ 7	$ 6,278
Marketing, gathering and compression	—	5,218	212	1	5,431
Oilfield services	—	154	1,553	(1,100)	607
Total Revenues	—	11,292	2,116	(1,092)	12,316
OPERATING EXPENSES:					
Oil, natural gas and NGL production	—	1,278	26	—	1,304
Production taxes	—	182	6	—	188
Marketing, gathering and compression	—	5,197	115	—	5,312
Oilfield services	—	301	1,096	(932)	465
General and administrative	—	431	105	(1)	535
Restructuring and other termination costs	—	5	2	—	7
Oil, natural gas and NGL depreciation, depletion and amortization	—	2,353	154	—	2,507
Depreciation and amortization of other assets	—	187	266	(149)	304
Impairment of oil and natural gas properties	—	3,192	123	—	3,315
Impairments of fixed assets and other	—	275	65	—	340
Net gains (losses) on sales of fixed assets	—	(269)	2	—	(267)
Total Operating Expenses	—	13,132	1,960	(1,082)	14,010
INCOME (LOSS) FROM OPERATIONS	—	(1,840)	156	(10)	(1,694)
OTHER INCOME (EXPENSE):					
Interest expense	(879)	45	(84)	841	(77)
Losses on investments	—	(167)	55	9	(103)
Net gain on sales of investments	—	29	1,063	—	1,092
Losses on purchases of debt	(200)	—	—	—	(200)
Other income (loss)	819	203	14	(1,028)	8
Equity in net earnings (losses) of subsidiary	(610)	436	—	174	—
Total Other Income (Expense)	(870)	546	1,048	(4)	720
INCOME (LOSS) BEFORE INCOME TAXES	(870)	(1,294)	1,204	(14)	(974)
INCOME TAX EXPENSE (BENEFIT)	(101)	(675)	470	(74)	(380)
NET INCOME (LOSS)	(769)	(619)	734	60	(594)
Net income attributable to noncontrolling interests	—	—	—	(175)	(175)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(769)	(619)	734	(115)	(769)
Other comprehensive income (loss)	6	(22)	—	—	(16)
COMPREHENSIVE INCOME ATTRIBUTABLE TO CHESAPEAKE	$ (763)	$ (641)	$ 734	$ (115)	$ (785)

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	$ —	$ 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 term loans, net of discount and offering 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	$ —	$ 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 Provided By (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

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2012
($ in millions)

	Parent[a]	Guarantor Subsidiaries[a]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ —	$ 1,711	$ 1,182	$ (56)	$ 2,837
CASH FLOWS FROM INVESTING ACTIVITIES:					
Drilling and completion costs	—	(8,605)	(325)	—	(8,930)
Acquisitions of proved and unproved properties	—	(3,622)	461	—	(3,161)
Proceeds from divestitures of proved and unproved properties	—	5,884	—	—	5,884
Additions to other property and equipment	—	(1,736)	(915)	—	(2,651)
Other investing activities	—	5,083	(316)	(893)	3,874
Net Cash Used In Investing Activities	—	(2,996)	(1,095)	(893)	(4,984)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	18,930	1,388	—	20,318
Payments on credit facilities borrowings	—	(20,651)	(999)	—	(21,650)
Proceeds from issuance of senior notes, net of discount and offering costs	1,263	—	—	—	1,263
Proceeds from issuance of term loans, net of discount and offering costs	5,722	—	—	—	5,722
Cash paid to purchase debt	(4,000)	—	—	—	(4,000)
Proceeds from sales of noncontrolling interests	—	63	1,014	—	1,077
Other financing activities	(477)	(299)	(820)	949	(647)
Intercompany advances, net	(2,282)	3,242	(960)	—	—
Net Cash Provided By (Used In) Financing Activities	226	1,285	(377)	949	2,083
Net increase (decrease) in cash and cash equivalents	226	—	(290)	—	(64)
Cash and cash equivalents, beginning of period	2	—	349	—	351
Cash and cash equivalents, end of period	$ 228	$ —	$ 59	$ —	$ 287

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent. As of December 31, 2012, $228 million was incorrectly presented in the Guarantor Subsidiaries column. The impact of this error was not material to any previously issued financial statements.

23. Recently Issued Accounting Standards

In April 2014, the FASB issued an accounting standards update that raises the threshold for a disposal or classification as held for sale to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This accounting standards update is effective for us beginning on January 1, 2015, and it is not expected to have a material impact on our consolidated financial statements.

In May 2014, the FASB issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration the company expects to receive in the exchange. The accounting standards update is effective for us beginning January 1, 2017, including retrospective application to comparative periods, and we are evaluating the impact on our consolidated financial statements.

Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2014 and 2013 are as follows:

	Quarters Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
	($ in millions except per share data)			
Total revenues	$ 5,046	$ 5,152	$ 5,703	$ 5,050
Gross profit[(a)]	$ 733	$ 610	$ 1,174	$ 960
Net income attributable to Chesapeake	$ 425	$ 191	$ 662	$ 639
Net income available to common stockholders	$ 375	$ 145	$ 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

	Quarters Ended			
	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
	($ in millions except per share data)			
Total revenues	$ 3,424	$ 4,675	$ 4,867	$ 4,541
Gross profit[(a)]	$ 217	$ 1,167	$ 436	$ 249
Net income (loss) attributable to Chesapeake[(b)]	$ 58	$ 580	$ 202	$ (116)
Net income (loss) available to common stockholders[(b)]	$ 15	$ 458	$ 156	$ (159)
Net earnings (loss) per common share:				
Basic	$ 0.02	$ 0.70	$ 0.24	$ (0.24)
Diluted	$ 0.02	$ 0.66	$ 0.24	$ (0.24)

(a) Total revenue less operating expenses.

(b) Includes $123 million of losses on the extinguishment of other financing and $203 million of impairments of fixed assets and other for the quarter ended December 31, 2013. See Note 5 and Note 17 for further discussion.

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, 2014	December 31, 2013
	($ in millions)	
Oil and oil and natural gas properties:		
Proved	$ 58,594	$ 56,157
Unproved	9,788	12,013
Total	68,382	68,170
Less accumulated depreciation, depletion and amortization	(38,238)	(35,577)
Net capitalized costs	$ 30,144	$ 32,593

Unproved properties not subject to amortization as of December 31, 2014, 2013 and 2012 consisted mainly of leasehold acquired through direct purchases of significant oil and natural gas property interests. We capitalized approximately $604 million, $815 million and $976 million of interest during 2014, 2013 and 2012, 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, 2014	2013	2012
		($ in millions)	
Acquisition of Properties:			
Proved properties	$ 214	$ 22	$ 332
Unproved properties	1,224	997	2,981
Exploratory costs	421	699	2,353
Development costs	4,204	4,888	6,733
Costs incurred[(a)(b)]	$ 6,063	$ 6,606	$ 12,399

(a) Exploratory and development costs are net of $679 million, $884 million and $784 million in drilling and completion carries received from our joint venture partners during 2014, 2013 and 2012, respectively.

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

Capitalized interest	$ 604	$ 815	$ 976
Asset retirement obligations	$ 39	$ 7	$ 32

In 2014, we invested approximately $1.289 billion, net of drilling and completion cost carries of $73 million, to convert 225 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 2014, 2013 and 2012. 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,		
	2014	2013	2012
	($ in millions)		
Oil, natural gas and NGL sales	$ 8,180	$ 7,052	$ 6,278
Oil, natural gas and NGL production expenses	(1,208)	(1,159)	(1,304)
Production taxes	(232)	(229)	(188)
Impairment of oil and natural gas properties	—	—	(3,315)
Depletion and depreciation	(2,683)	(2,589)	(2,507)
Imputed income tax provision[(a)]	(1,485)	(1,169)	404
Results of operations from oil, natural gas and NGL producing activities	$ 2,572	$ 1,906	$ (632)

(a) The imputed income tax provision is hypothetical (at the effective income 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, 2014, 2013 and 2012. Independent petroleum engineering firms estimated an aggregate of 79%, 81% and 89% of our estimated proved reserves (by volume) as of December 31, 2014, 2013 and 2012, respectively, as set forth below.

	December 31,		
	2014	2013	2012
Ryder Scott Company, L.P.	54%	51%	44%
PetroTechnical Services, Division of Schlumberger Technology Corporation	25%	30%	24%
Netherland, Sewell & Associates, Inc.	—%	—%	21%

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 or in which the cost of the required equipment is relatively minor compared to the cost of 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 2014, 2013 and 2012.

	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[(a)]	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

	Oil (mmbbl)	Gas (bcf)	NGL (mmbbl)	Total (mmboe)
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[(c)]	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
December 31, 2012				
Proved reserves, beginning of period	291.6	15,515	253.9	3,132
Extensions, discoveries and other additions	374.0	3,317	139.4	1,065
Revisions of previous estimates	(67.5)	(6,080)	(47.3)	(1,127)
Production	(31.3)	(1,129)	(17.6)	(237)
Sale of reserves-in-place	(75.5)	(704)	(31.7)	(225)
Purchase of reserves-in-place	4.2	14	0.6	7
Proved reserves, end of period[(d)]	495.5	10,933	297.3	2,615
Proved developed reserves:				
Beginning of period	124.0	8,578	130.6	1,684
End of period	162.9	7,174	132.1	1,491
Proved undeveloped reserves:				
Beginning of period	167.6	6,937	123.3	1,447
End of period[(b)]	332.6	3,759	165.2	1,124

(a) 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.

(b) As of December 31, 2014, 2013 and 2012, there were no PUDs that had remained undeveloped for five years or more.

(c) 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.

(d) Includes 4 mmbbls of oil, 91 bcf of natural gas and 9 mmbbls of NGL reserves owned by the Chesapeake Granite Wash Trust, 2 mmbbls of oil, 45 bcf of natural gas and 4 mmbbls of NGL of which are attributable to the noncontrolling interest holders.

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.

During 2012, we acquired approximately 7 mmboe of proved reserves through purchases of oil and natural gas properties for consideration of $332 million, and we sold 225 mmboe of our proved reserves for approximately $2.381 billion. During 2012, we recorded downward revisions of 1.127 bboe to the December 31, 2011 estimates of our reserves. Included in the revisions were 902 mmboe of downward revisions resulting from lower natural gas prices in 2012 and 225 mmboe of downward revisions resulting from changes to previous estimates. Lower prices decrease the economic lives of the underlying oil and natural gas properties and thereby decrease the estimated future reserves. The oil and natural gas prices used in computing our reserves as of December 31, 2012 were $94.84 per bbl and $2.76 per mcf, respectively, before price differentials. Including the effect of price differential adjustments, the prices used in computing our reserves as of December 31, 2012 were $91.78 per barrel of oil, $1.75 per mcf of natural gas and $30.81 per barrel of NGL. The non price-related revisions were primarily the result of our continued execution of our strategy to shift the Company’s drilling focus from natural gas to liquids-rich areas and to drill in the "core of the core" of our acreage positions. As rigs were reallocated, PUDs were removed from various noncore areas resulting in downward revisions.

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, 2014, 2013 and 2012 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, 2014	2013	2012
	($ in millions)		
Future cash inflows	$ 72,557 [(a)]	$ 76,094 [(b)]	$ 73,754 [(c)]
Future production costs	(17,036)	(18,196)	(18,809)
Future development costs	(7,556)	(9,563)	(12,656)
Future income tax provisions	(12,494)	(12,196)	(9,824)
Future net cash flows	35,471	36,139	32,465
Less effect of a 10% discount factor	(18,338)	(18,749)	(17,799)
Standardized measure of discounted future net cash flows[(d)]	$ 17,133	$ 17,390	$ 14,666

(a) Calculated using prices of $94.98 per bbl of oil and $4.35 per mcf of natural gas, before field differentials.

(b) Calculated using prices of $96.82 per bbl of oil and $3.67 per mcf of natural gas, before field differentials.

(c) Calculated using prices of $94.84 per bbl of oil and $2.76 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, 2014	2013	2012
	($ in millions)		
Standardized measure, beginning of period[(a)]	$ 17,390	$ 14,666	$ 15,630
Sales of oil and natural gas produced, net of production costs[(b)]	(5,722)	(5,535)	(3,867)
Net changes in prices and production costs	(634)	2,021	(2,720)
Extensions and discoveries, net of production and development costs	5,156	6,008	11,115
Changes in future development costs	1,946	1,287	3,687
Development costs incurred during the period that reduced future development costs	1,178	1,582	1,046
Revisions of previous quantity estimates	(715)	(805)	(8,699)
Purchase of reserves-in-place	215	26	285
Sales of reserves-in-place	(1,788)	(1,976)	(3,246)
Accretion of discount	2,168	1,777	1,988
Net change in income taxes	(593)	(1,180)	1,142
Changes in production rates and other	(1,468)	(481)	(1,695)
Standardized measure, end of period[(a)(c)(d)]	$ 17,133	$ 17,390	$ 14,666

(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, 2014.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the period ended December 31, 2014, which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *Other Information*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance*

The names of executive officers and certain other senior officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2015 (the "2015 Proxy Statement").

ITEM 11. *Executive Compensation*

The information called for by this Item 11 is incorporated herein by reference to the 2015 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 2015 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 2015 Proxy Statement.

ITEM 14. *Principal Accountant Fees and Services*

The information called for by this Item 14 is incorporated herein by reference to the 2015 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*. Schedule II is included in Item 8 of Part II of this report with our consolidated financial statements. No other 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 27, 2015

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 27, 2015
/s/ DOMENIC J. DELL'OSSO, JR. **Domenic J. Dell'Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2015
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President - Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2015
/s/ ARCHIE W. DUNHAM **Archie W. Dunham**	Chairman of the Board	February 27, 2015
/s/ VINCENT J. INTRIERI **Vincent J. Intrieri**	Director	February 27, 2015
/s/ JOHN J. LIPINSKI **John J. Lipinski**	Director	February 27, 2015
/s/ R. BRAD MARTIN **R. Brad Martin**	Director	February 27, 2015
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	February 27, 2015
/s/ FREDRIC M. POSES **Frederic M. Poses**	Director	February 27, 2015
/s/ LOUIS A. RASPINO **Louis A. Raspino**	Director	February 27, 2015
/s/ THOMAS L. RYAN **Thomas L. Ryan**	Director	February 27, 2015

INDEX TO EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date	
2.1.1*	Purchase and Sale Agreement by and between Chesapeake Appalachia, L.L.C. and Southwestern Energy Production Company dated October 14, 2014.					X
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.					X
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.					X
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	6/9/2014	
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 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 2.75% Contingent Convertible Senior Notes due 2035.	8-K	001-13726	4.12.2	11/15/2005	

4.4**	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
4.5**	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
4.6**	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 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	5/29/2008
4.7**	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
4.8.1**	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
4.8.2	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
4.8.3	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
4.8.4	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
4.8.5	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
4.8.6	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
4.8.7	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

4.8.8	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
4.9.1**	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
4.9.2	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
4.9.3	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
4.10**	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
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†	Chesapeake's 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-Q	001-13726	10.7	8/6/2013
10.3.1†	Chesapeake's 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	6/20/2013
10.3.2†	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
10.3.3†	Form of Nonqualified Stock Option Agreement for 2005 Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1	2/4/2013
10.3.4†	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
10.3.5†	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
10.3.6†	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
10.3.7†	Form of 2014 Performance Share Unit Award Agreement for 2005 Amended and Restated Long Term Incentive Plan.	10-K	001-13726	10.4.7	2/26/2014

10.3.8†	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	
10.3.9†	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	
10.3.10†	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	
10.4†	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan, as amended.					X
10.5†	Chesapeake Energy Corporation Deferred Compensation Plan for Non-Employee Directors.	10-K	001-13726	10.16	3/13/2013	
10.6†	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	
10.7†	Employment Agreement dated as of January 1, 2013 between Domenic J. Dell'Osso, Jr. and Chesapeake Energy Corporation.	10-K	001-13726	10.19	3/1/2013	
10.8†	Employment Agreement dated as of January 1, 2013 between James R. Webb and Chesapeake Energy Corporation.					X
10.9†	Employment Agreement dated as of August 14, 2013 between M. Christopher Doyle and Chesapeake Energy Corporation.	10-Q/A	001-13726	10.1	11/7/2013	
10.10†	Employment Agreement dated as of August 4, 2013 between Mikell Jason Pigott and Chesapeake Energy Corporation.	10-Q/A	001-13726	10.2	11/7/2013	
10.11†	Form of Employment Agreement dated as of January 1, 2013 between Executive Vice President/Senior Vice President and Chesapeake Energy Corporation.	8-K	001-13726	10.1	1/7/2013	
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	
10.14.1†	Chesapeake Energy Corporation 2014 Long Term Incentive Plan.	DEF 14A	001-13726	Exhibit F	4/30/2014	
10.14.2†	Form of Restricted Stock Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.2	8/6/2014	
10.14.3†	Form of Restricted Stock Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.3	8/6/2014	
10.14.4†	Form of Nonqualified Stock Option Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.4	8/6/2014	

10.14.5†	Form of Performance Share Unit Award Agreement for 2014 Long Term Incentive Plan.	10-Q	001-13726	10.5	8/6/2014	
10.14.6†	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

* 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

Archie W. Dunham [1,2]
Chairman of the Board
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

R. Brad Martin [1,2,4]
Chairman
RBM Venture Company
Former Chairman and
Chief Executive Officer
Saks Incorporated
Memphis, Tennessee

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

Kimberly K. Querrey [3]
(appointed April 2015)
President and Managing Member
SQ Advisors, LLC
Naples, Florida

Louis A. Raspino [3]
Former President and
Chief Executive Officer
Pride International, Inc.
Houston, Texas

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

Douglas J. Jacobson
Executive Vice President –
Acquisitions & Divestitures

John M. Kapchinske
Executive Vice President –
Exploration & Subsurface Technology

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

CORPORATE HEADQUARTERS

6100 North Western Avenue
Oklahoma City, OK 73118
(405) 848-8000

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 23, 2015, the record date for our 2015 Annual Meeting of Shareholders, there were approximately 343,600 beneficial owners of our common stock.

COMMON STOCK DIVIDENDS

During 2014, the company announced a cash dividend of $0.0875 per share on March 11, June 16, September 22 and December 15 for a total dividend declared of $0.35 per share.

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 and 2014
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 2014 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.

CHK
LISTED
NYSE

6100 NORTH WESTERN AVENUE
OKLAHOMA CITY, OK 73118

CHK.COM

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