CHESAPEAKE ENERGY CORP
Form 10-K
February 27, 2015

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
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PART I

Item 1. Business

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

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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-

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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;

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- 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.

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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	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.

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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 Production Expenses	$/boe	2013 Production Expenses	$/boe	2012 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

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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

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	Volume (tbtu)	Weighted Average Price Fixed ($ per mmbtu)	Call	Put	Differential	Fair Value Asset (Liability) ($ 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.

	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 ($ in millions)	Weighted Average Rate Fixed		Floating[a]	Fair Value Hedge	Fair Value Asset (Liability) ($ 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	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.
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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.

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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)