CHESAPEAKE ENERGY CORP
Form 10-K
March 01, 2013
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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, 2012
[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to
Commission File No. 1-13726
Chesapeake Energy Corporation
(Exact name of registrant as specified in its charter)

Oklahoma	73-1395733
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

6100 North Western Avenue	
Oklahoma City, Oklahoma	73118
(Address of principal executive offices)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01	New York Stock Exchange
7.625% Senior Notes due 2013	New York Stock Exchange
9.5% Senior Notes due 2015	New York Stock Exchange
6.25% Senior Notes due 2017	New York Stock Exchange
6.5% Senior Notes due 2017	New York Stock Exchange
6.875% Senior Notes due 2018	New York Stock Exchange
7.25% Senior Notes due 2018	New York Stock Exchange
6.775% 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
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

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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, 2012 was approximately $12.2 billion. At February 21, 2013, there were 667,567,791 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the proxy statement for the 2013 Annual Meeting of Shareholders are incorporated by reference in Part III.

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2012 ANNUAL REPORT ON FORM 10-K
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Part I

ITEM 1. Business

Our Business

We are the second-largest producer of natural gas, a top 11 producer of liquids and the most active driller of wells in the U.S. We own interests in approximately 45,400 producing natural gas and oil wells that are currently producing approximately 3.9 bcfe per day, net to our interest. The Company has built a large resource base of onshore U.S. unconventional natural gas and liquids assets. Our core natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. In addition, we have built 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 Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas; and the Niobrara Shale in the Powder River Basin in Wyoming. We have also vertically integrated many of our operations and own substantial marketing, compression and oilfield services businesses.

The map below illustrates the locations of Chesapeake's natural gas and oil exploration and production operations.

The Company's December 31, 2012 estimated proved reserves were 15.690 tcfe, a decrease of 3.099 tcfe, or 17%, from 18.789 tcfe at year-end 2011. The decrease was primarily price related as natural gas prices in 2012 declined to the lowest levels in ten years. The 2012 proved reserve movement included 6.391 tcfe of extensions, downward revisions of 5.414 tcfe resulting from lower natural gas prices and downward revisions of 1.349 tcfe resulting from changes to previous estimates. In 2012, we produced 1.422 tcfe, acquired 42 bcfe and divested 1.347 tcfe of estimated proved reserves, including the disposition of 1.013 tcfe associated with the sale of our Permian Basin assets in September and October 2012.

Natural gas prices used in estimating proved reserves as of December 31, 2012 decreased by $1.36, or 33%, to $2.76 per mcf from $4.12 per mcf as of December 31, 2011 using the trailing 12-month average prices required by the Securities and Exchange Commission (SEC). The reserve reductions included the loss of significant proved undeveloped reserves, primarily in the Barnett Shale and the Haynesville Shale plays, for which future development is uneconomic at the natural gas prices used in the reserve estimates. As a result of lower natural gas prices leading to lower estimated reserves, we were required to impair the carrying value of our natural gas and oil properties in the 2012 third quarter. See Natural Gas and Oil Properties in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of this impairment and its impact on the consolidated financial statements.

Our daily production for 2012 averaged 3.886 bcfe, an increase of 614 mmcfe, or 19%, over the 3.272 bcfe of daily production for 2011, and consisted of 3.084 bcf (80% on a natural gas equivalent basis), approximately 85,420 bbls of oil (13% on a natural gas equivalent basis) and approximately 48,130 bbls of NGL (7% on a natural gas equivalent basis). Our natural gas production in 2012 grew by 12%, or 333 mmcf per day; our oil production increased by 84%, or approximately 38,950 bbls per day; and our NGL production increased by 19%, or approximately 7,820 bbls per day.

Information About Us

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. 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 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. References to "Chesapeake", the "Company", "us", "we" and "our" in this report are to Chesapeake Energy Corporation together with its subsidiaries, unless the context otherwise requires.

Business Strategy

Since our inception in 1989, Chesapeake's primary goal has been to create value for investors by building and developing one of the largest onshore natural gas and liquids-rich resource bases in the U.S. Key elements of this business strategy are further explained below.

Grow Through the Drillbit. We believe that our most distinctive characteristic is our commitment and ability to grow production and proved reserves organically through the drillbit at a low cost in areas with large unconventional accumulations of natural gas and liquids. We are currently utilizing 83 operated drilling rigs and 31 non-operated drilling rigs to conduct the most active drilling program in the U.S. We are active in most of the nation's major unconventional plays, where we drill more horizontal wells than any other company in the industry. For many years, we have invested large amounts of capital in undeveloped leasehold, three dimensional (3-D) seismic information and human resources to take full advantage of our capacity to grow through the drillbit. As a result of those investments, we have been able to increase production for 23 consecutive years. We believe the success of our drilling program is largely due to our recognition, earlier than most of our competitors, that advanced horizontal drilling and completion techniques would enable development of previously uneconomic natural gas and liquids-rich reservoirs and that, as a consequence, various unconventional formations could be recognized and developed as potentially prolific reservoirs. For 2013 and beyond, we anticipate spending significantly less than in previous years on undeveloped leasehold, oilfield service assets and other fixed assets, and at the same time benefiting from our past investment in non-drilling assets that facilitate our ability to drill the best wells in the most efficient manner.

Increase Liquids Production. In recognition of the value gap between liquids and natural gas prices that has widened to historic levels in the last five years, we have directed a significant portion of our technological and leasehold acquisition expertise to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and likely more profitable portfolio between natural gas and liquids. To date, we have established production in multiple liquids-rich plays on approximately 6.4 million net acres. Our production of liquids averaged approximately 133,550 bbls per day during 2012, a 54% increase over the average during 2011, as a result of the increased development of our unconventional liquids-rich plays. In 2012, approximately 85% of our drilling and completion expenditures were allocated to liquids-rich plays, compared to 50% in 2011 and 30% in 2010. We are projecting that 85% of our operated drilling and completion expenditures will be allocated to liquids development in 2013 as well, and we expect to increase our liquids production through our drilling activities by approximately 27% in 2013 compared to 2012, net of expected asset sales. We project that liquids will account for more than 25% of our 2013 production and approximately 60% of our natural gas, oil and NGL revenue, after differentials and realized hedging.

Control Substantial Land and Drilling Location Inventories. Recognizing that better horizontal drilling and completion technologies, when applied to various new unconventional reservoirs, would likely create a unique opportunity to capture many years worth of drilling opportunities, we aggressively acquired leases in natural gas shale plays from

2006 through 2008 and unconventional oil plays from 2009 through 2011. We believe our lease acquisition program has given us competitive advantages in some of the best unconventional resource plays in the U.S. As of December 31, 2012, we held approximately 15 million net acres of onshore leasehold in the U.S. We believe this extensive leasehold position provides substantial opportunities for future growth and offers valuable divestiture opportunities as we focus on developing the most promising of our plays. Our undeveloped leasehold acquisition phase is now substantially complete. We spent approximately 50% less on new leasehold in 2012 than in 2011 and are forecasting to spend approximately 75% less in 2013 than in 2012.

Focus our Operations in the "Core of the Core" of Our Leasehold. We have made significant acquisitions of leasehold inventory and necessary investments in infrastructure, oilfield services, seismic data and human resources that have allowed us to drill wells more successfully and at a lower cost. Recently, we have shifted our focus to the development of the 10 plays in which we have a #1 or #2 ownership position. In an effort to optimize our portfolio around our core natural gas and oil properties, during 2012 we completed sales of non-core natural gas and oil properties, midstream and other assets for proceeds of approximately $12 billion (including $1.25 billion from the sale of a preferred security in a subsidiary), and in 2013 we are planning to sell additional natural gas and oil properties as well as midstream, certain oilfield services and other assets that do not fit our long-term plans for expected additional proceeds of approximately $4 - $7 billion. We expect that a much higher percentage of our total expenditures in 2013 will be directed toward drilling and completion activities. By concentrating on the "core of the core" of our assets, we believe we can leverage our past investments to prioritize our drilling program around our highest-return assets and enhance returns on capital.

Improve Our Balance Sheet through Reduction of Debt. Our strategic and financial plan calls for reduced long-term debt along with continued growth in production. We believe that reduced debt and continued growth in our asset base will lead to investment grade metrics. We expect to reduce debt primarily with proceeds from asset sales. Among the several benefits of lower debt are lower borrowing costs, and we believe improved credit metrics will lead to more favorable debt ratings by the major ratings agencies over time.

Mitigate Natural Gas and Oil Price Risk. We have used and intend to continue using our hedging program to mitigate the risks inherent in developing and producing natural gas and liquids-rich resources and to provide a level of cash flow certainty. We intend to periodically use the volatility in natural gas and oil prices to our benefit by adjusting our hedge position when market prices reach levels that management believes are either unsustainable for the long term, have material risk in the short term or offer unusually high rates of return on our invested capital. We currently have downside hedge protection on approximately 85% of our expected 2013 oil production and 50% of our expected 2013 natural gas production, which equates to approximately 72% of our expected 2013 natural gas, oil and NGL revenue, after differentials. We have also hedged a significant portion of our projected 2014 oil production.

Focus on Low Costs and Vertical Integration. By minimizing lease operating expenses through focused activities, vertical integration and increased scale, we strive to deliver attractive profit margins and financial returns through all phases of the commodity price cycle. Our operational efficiencies are reflected in faster spud-to-spud cycle times, overall decreases in production costs per unit and economies of scale from pad drilling. We believe our low cost structure is the result of management's effective cost-control programs, a high-quality asset base and access to oilfield services, especially those we own through our wholly and non-wholly owned subsidiaries, and natural gas processing and transportation infrastructures that exist in our key operating areas. Our high level of drilling activity and production volumes create considerable value for our oilfield services and compression businesses. As of December 31, 2012, we operated approximately 27,200 of our 45,400 gross wells, which delivered approximately 85% of our daily production volume. This large percentage of operated properties provides us with a high degree of operational flexibility and cost control.

Maintain an Entrepreneurial Culture. As an employer of approximately 12,000 people and an indirect employer of tens of thousands more, we take pride in our innovative and aggressive implementation of our business strategy and strive to be as entrepreneurial today as we were when we were a much smaller company. We have maintained an unusually flat organizational structure as we have grown to help ensure that important information travels rapidly through the Company and decisions are made and implemented quickly. Our efforts in the development of our human resources have been recognized by many, most recently Fortune Magazine, which in January 2013 named Chesapeake the 26th best company to work for in the U.S., including the second highest ranked company within the U.S. oil and gas industry. This was the sixth year in a row that we have been named by Fortune as one of the 100 Best Companies to Work for in America.

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Operating Divisions

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

Southern Division. Primarily includes the Haynesville/Bossier Shales in northwestern Louisiana and East Texas and the Barnett Shale in the Fort Worth Basin of north-central Texas.

Northern Division. The Mid-Continent region, principally the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas, including the Mississippi Lime, Cleveland and Tonkawa tight sands and Granite Wash plays.

Eastern Division. Primarily includes the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania and the Utica Shale in Ohio and Pennsylvania.

Western Division. Primarily includes the Eagle Ford Shale in South Texas, the Niobrara Shale in the Powder River Basin in Wyoming and, prior to November 2012, the Permian and Delaware Basins of West Texas and southern New Mexico. In September and October 2012, we sold all of our producing properties, gathering business and substantially all of our leasehold in the Permian and Delaware Basins.

Well Data

At December 31, 2012, we had interests in approximately 45,400 gross (21,200 net) productive wells, including properties in which we held an overriding royalty interest, of which 37,300 gross (18,500 net) were classified as primarily natural gas productive wells and 8,100 gross (2,700 net) were classified as primarily oil productive wells. Chesapeake operates approximately 27,200 of its 45,400 productive wells. During 2012, we drilled 1,642 gross (1,111 net) wells and participated in another 959 gross (161 net) wells operated by other companies. We operate approximately 85% of our current daily production volumes.

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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.

	2012				2011				2010			
	Gross	%	Net	%	Gross	%	Net	%	Gross	%	Net	%
Development:												
Productive	2,075	99	956	99	2,536	99	1,077	99	2,721	99	1,031	99
Dry	21	1	5	1	10	1	3	1	30	1	12	1
Total	2,096	100	961	100	2,546	100	1,080	100	2,751	100	1,043	100
Exploratory:												
Productive	495	98	305	98	430	99	201	99	265	95	99	93
Dry	10	2	6	2	3	1	1	1	15	5	7	7
Total	505	100	311	100	433	100	202	100	280	100	106	100

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

	2012		2011		2010	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Southern	363	183	1,104	550	1,023	495
Northern	942	441	1,076	342	1,371	369
Eastern	578	264	371	149	367	140
Western	718	384	428	241	270	145
Total	2,601	1,272	2,979	1,282	3,031	1,149

At December 31, 2012, we had 1,033 (461 net) wells in drilling or completing status.

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Production, Sales, Prices and Expenses

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

	Years Ended December 31,		
	2012	2011	2010
Net Production:			
Natural gas (bcf)	1,128.8	1,004.1	924.9
Oil (mmbbl)	31.3	17.0	10.9
NGL (mmbbl)	17.6	14.7	7.5
Natural gas equivalent (bcfe)[(a)]	1,422.1	1,194.2	1,035.2
Natural Gas, Oil and NGL Sales ($ in millions):			
Natural gas sales	$2,004	$3,133	$3,169
Natural gas derivatives – realized gains (losses)	328	1,656	1,982
Natural gas derivatives – unrealized gains (losses)	(331)	(669)	425
Total natural gas sales	2,001	4,120	5,576
Oil sales	2,829	1,523	822
Oil derivatives – realized gains (losses)	39	(60)	74
Oil derivatives – unrealized gains (losses)	857	(128)	(1,033)
Total oil sales	3,725	1,335	(137)
NGL sales	526	603	257
NGL derivatives – realized gains (losses)	(9)	(42)	—
NGL derivatives – unrealized gains (losses)	35	8	(49)
Total NGL sales	552	569	208
Total natural gas, oil and NGL sales	$6,278	$6,024	$5,647
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$1.77	$3.12	$3.43
Oil ($ per bbl)	$90.49	$89.80	$75.29
NGL ($ per bbl)	$29.89	$40.96	$34.38
Natural gas equivalent ($ per mcfe)	$3.77	$4.40	$4.10
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$2.07	$4.77	$5.57
Oil ($ per bbl)	$91.74	$86.25	$82.10
NGL ($ per bbl)	$29.37	$38.12	$34.38
Natural gas equivalent ($ per mcfe)	$4.02	$5.70	$6.09
Other Operating Income[(b)] ($ in millions):			
Marketing, gathering and compression net margin	$119	$123	$127
Oilfield services net margin	$142	$119	$32
Expenses ($ per mcfe):			
Natural gas, oil and NGL production	$0.92	$0.90	$0.86
Production taxes	$0.13	$0.16	$0.15
General and administrative expenses	$0.38	$0.46	$0.44
Natural gas, oil and NGL depreciation, depletion and amortization	$1.76	$1.37	$1.35
Depreciation and amortization of other assets	$0.21	$0.24	$0.21
Interest expense[(c)]	$0.06	$0.03	$0.08

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(a) Natural gas 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. Given recent natural gas, oil and NGL prices, the price for an mcfe of natural gas is significantly less than the price for an mcfe of oil or NGL.

(b) Includes revenue and operating costs and excludes depreciation and amortization of other assets. See Depreciation and Amortization of Other Assets under Results of Operations in Item 7 of this report for details of the depreciation and amortization of other assets associated with our marketing, gathering and compression and oilfield services operating segments.

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

Natural Gas, Oil and NGL Reserves

The tables below set forth information as of December 31, 2012 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) at such date. 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 natural gas, oil and NGL reserves we own. All of our estimated natural gas and oil reserves are located within the U.S.

	December 31, 2012			
	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)[(a)]
Proved developed	7,174	162.9	132.1	8,944
Proved undeveloped	3,759	332.6	165.2	6,746
Total proved[(b)]	10,933	495.5	297.3	15,690

	Proved Developed	Proved Undeveloped	Total Proved
	($ in millions)		
Estimated future net revenue[(c)]	$20,510	$21,779	$42,289
Present value of estimated future net revenue[(c)]	$10,793	$6,980	$17,773
Standardized measure[(c)(d)]			$14,666

Operating Division	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Natural Gas Equivalent (bcfe)[(a)]	Percent of Proved Reserves	Present Value ($ millions)
Southern	3,532	11.7	23.4	3,742	24 %	$1,527
Northern	2,680	153.5	130.8	4,385	28 %	5,834
Eastern	3,891	9.5	34.3	4,155	26 %	2,901
Western	830	320.8	108.8	3,408	22 %	7,511
Total	10,933	495.5	297.3	15,690	100 %	$17,773 (c)

(a) Natural gas equivalent based on six mcf of natural gas to one barrel of oil or NGL.

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

(c) 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, 2012. For the purpose of determining "prices", we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended

December 31, 2012. The prices used in our reserve reports were $2.76 per mcf of natural gas and $94.84 per barrel of oil, before price differential adjustments. Including the effect of price differential adjustments, the prices used in our reserve reports were $1.75 per mcf of natural gas, $91.78 per barrel of oil and $30.81 per barrel 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, 2012. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue differs from the standardized measure only because the former does not include the effects of estimated future income tax expenses ($3.1 billion as of December 31, 2012).

Management uses future net revenue, which is calculated without deducting estimated future income tax expenses, and the present value thereof, as one 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 present value 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.

(d) Additional information on the standardized measure is presented in Note 10 of the notes to our consolidated financial statements included in Item 8 of this report.

As of December 31, 2012, our reserve estimates included 6.746 tcfe of reserves classified as proved undeveloped (PUD), compared to 8.683 tcfe as of December 31, 2011. Presented below is a summary of changes in our proved undeveloped reserves for 2012.

	Total (bcfe)
Proved undeveloped reserves, beginning of period	8,683
Extensions, discoveries and other additions	4,161
Revisions of previous estimates[a]	(4,778)
Developed	(961)
Sale of reserves-in-place	(363)
Purchase of reserves-in-place	4
Proved undeveloped reserves, end of period	6,746

(a) Included in this amount are 4,009 bcfe of downward price-related revisions.

As of December 31, 2012, there were no PUDs that had remained undeveloped for five years or more. In 2012, we invested approximately $1.035 billion, net of drilling and completion cost carries of $86 million, to convert 961 bcfe of PUDs to proved developed reserves. In 2013, we estimate that we will invest approximately $2.4 billion, net of drilling and completion cost carries of $95 million, for PUD conversion.

The future net revenue attributable to our estimated proved undeveloped reserves of $21.779 billion as of December 31, 2012, and the $6.980 billion present value thereof, has been calculated assuming that we will expend approximately $12.0 billion to develop these reserves: $2.4 billion in 2013, $2.2 billion in 2014, $2.6 billion in 2015, $2.6 billion in 2016 and $2.2 billion in 2017, 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 the relative success in an individual developmental drilling prospect leading to an additional drilling opportunity, rig availability, title issues or delays, and the effect that acquisitions or dispositions may have on prioritizing developmental drilling plans.

The SEC's rules for reporting reserves allow the booking of proved undeveloped reserves at locations greater distances from producing wells than immediate offsets. All proved reserves are required to meet reasonable certainty standards; thus, locations more than direct offsets to producing wells must be shown to 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.

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Our proved reserves as of December 31, 2012 included PUDs more than directly offsetting producing wells in two resource plays: the Marcellus Shale and the Eagle Ford Shale. In all other areas, we restricted PUD locations to immediate offsets to producing wells. Within the 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 area was 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 this proved area could be booked as PUDs. However, due to other factors and requirements of SEC reserves reporting rules, numerous locations within the proved area of these two statistically evaluated plays have not yet been booked as PUDs.

Our annual net decline rate on producing properties is projected to be 33% from 2013 to 2014, 22% from 2014 to 2015, 17% from 2015 to 2016, 14% from 2016 to 2017 and 12% from 2017 to 2018. Of our 8.9 tcfe of proved developed reserves as of December 31, 2012, 1.2 tcfe were non-producing.

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue was 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 natural gas and oil production sold subsequent to December 31, 2012. 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, 2012, 2011 and 2010, and the changes in quantities and standardized measure of such reserves for each of the three years then ended, are shown in Note 10 of the notes to the consolidated financial statements included in Item 8 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 natural gas and oil 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 such estimates, and such revisions may be material. Accordingly, reserve estimates often differ from the actual quantities of natural gas, oil 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.

Chesapeake's management uses forward-looking market-based data in developing its drilling plans, assessing its capital expenditure needs and projecting future cash flows. We believe that using the 10-year average future NYMEX strip prices yields a better indication of the likely economic producibility of proved reserves than the trailing average 12-month price required by the SEC's reserves reporting rules. Reserve volumes represent estimated production to be sold in the future. Futures prices, such as the 10-year average NYMEX strip prices, represent an unbiased consensus estimate by market participants about the likely prices to be received for future production. We hedge substantial amounts of future production based on futures prices. While historical data, such as the trailing 12-month average price required by the SEC's reporting rule, facilitate comparisons of proved reserves from company to company and may be helpful in discerning trends, such as price-related effects on end-user demand, the price at which we can sell our production in the future is by far the major determinant of the likely economic producibility of our reserves. A 12-month average price adjusts slowly to falling or rising prices, further detracting from its usefulness as a predictor of the prices at which future production will actually be sold.

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The table below compares our estimated proved reserves and associated present value (discounted at an annual rate of 10%) of estimated future revenue before income tax using the 2012 12-month average prices of $2.76 per mcf and $94.84 per bbl, before price differential adjustments, reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2012, which were $4.85 per mcf and $87.90 per bbl, before price differential adjustments. Our cost and other assumptions are the same under the two pricing scenarios.

	December 31, 2012				
	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)	Present Value ($ in millions)
2012 12-month average prices (SEC)[(a)]	10,933	495.5	297.3	15,690	$17,773
10-year average future NYMEX strip prices as of December 31, 2012[(b)]	14,742	497.2	304.2	19,550	$27,927

(a) Volumes represent proved reserves as defined in Rule 4-10(a)(22) of Regulation S-X.
(b) Volumes do not represent proved reserves as defined in Rule 4-10(a)(22) of Regulation S-X.

Reserves Estimation

Chesapeake's Reservoir Engineering Department prepared approximately 11% 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 Vice President of Corporate Reserves is the technical person primarily responsible for overseeing the preparation of the Company's reserve estimates. His qualifications include the following:

- 37 years of practical experience in petroleum engineering, including 34 years of this experience in the estimation and evaluation of reserves;
- registered professional engineer in the state of Oklahoma;
- Bachelor of Science degree in Petroleum Engineering; and
- member in good standing of the Society of Petroleum Engineers.

We ensure that the key members of the 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 Reservoir Engineering Department reviews all of the Company's reported proved reserves at the close of each quarter.
- Each quarter, Reservoir Engineering Department managers, the Vice President of Corporate Reserves, the Executive Vice President of Production and the Chief Operating Officer review all significant reserves changes and all new proved undeveloped reserves additions.
- The Reservoir Engineering Department reports independently of any of our operating divisions.

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We engaged three third-party engineering firms to prepare portions of our reserves estimates comprising approximately 89% of our estimated proved reserves (by volume) at year-end 2012. The portion of our estimated proved reserves prepared by each of our third-party engineering firms as of December 31, 2012 is presented below.

	% Prepared (by Volume)	Operating Division
Ryder Scott Company, L.P.	44%	Northern, Western
PetroTechnical Services, Division of Schlumberger Technology Corporation	24%	Eastern
Netherland, Sewell & Associates, Inc.	21%	Southern

Copies of the reports issued by the engineering firms are filed with this report as Exhibits 99.1 through 99.3. 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
- Bachelor of Science degree in Electrical Engineering
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers

PetroTechnical Services, Division of Schlumberger Technology Corporation

- over 20 years of practical experience in petroleum geology and in the estimation and evaluation of reserves
- registered professional geologist license in the Commonwealth of Pennsylvania
- certified petroleum geologist of the American Association of Petroleum Geologists
- Bachelor of Science degree in Petroleum and Natural Gas Engineering

Netherland, Sewell & Associates, Inc.

- over 30 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves
- registered professional engineer in the state of Texas
- Bachelor of Science degree in Petroleum Engineering

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

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

	Years Ended December 31,		
	2012	2011	2010
	($ in millions)		
Acquisition of Properties:			
Proved properties	$332	$48	$243
Unproved properties	2,981	4,736	6,953
Exploratory costs	2,353	2,261	872
Development costs	6,733	5,497	4,741
Costs incurred[(a)(b)]	$12,399	$12,542	$12,809

(a) Exploratory and development costs are net of joint venture drilling and completion cost carries of $784 million, $2.570 billion and $1.151 billion in 2012, 2011 and 2010, respectively.

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

Capitalized interest	$976	$727	$711
Asset retirement obligations	$32	$3	$2

As of December 31, 2012, there were no PUDs that had remained undeveloped for five years or more. In 2012, we invested approximately $1.035 billion, net of drilling and completion cost carries of $86 million, to convert 961 bcfe of PUDs to proved developed reserves.

A summary of our exploration and development, acquisition and divestiture activities in 2012 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	363	183	$1,060	$181	$12	$(50)	$—	$1,203
Northern	942	441	3,055	559	14	(838)	(1,098)	1,692
Eastern	578	264	1,785	1,727	—	(731)	(7)	2,774
Western	718	384	3,186	514	306	(1,800)	(1,356)	850
Total	2,601	1,272	$9,086	$2,981	$332	$(3,419)	$(2,461)	$6,519

(a) Includes capitalized internal costs of $410 million and related capitalized interest of $976 million.

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Acreage

The following table sets forth as of December 31, 2012 the gross and net developed and undeveloped natural gas and oil 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	1,018	653	327	189	141	65	1,486	907
Northern	4,606	2,458	4,242	2,863	1,056	178	9,904	5,499
Eastern	1,972	1,497	5,913	3,413	706	508	8,591	5,418
Western	625	355	4,941	2,822	350	31	5,916	3,208
Total	8,221	4,963	15,423	9,287	2,253	782	25,897	15,032

We actively acquire new leases, most of which have a three to five-year term. Managing lease expirations to ensure that we do not experience unintended material expirations is an important part of our business. 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 leasehold asset sales and joint venture transactions to high-grade our lease inventory or to raise capital for additional development and letting some leases expire that are no longer part of our development plans.

The following table sets forth as of December 31, 2012, the expiration periods of gross and net undeveloped leasehold acres, unless production from the leasehold acreage is established prior to the expiration date, or we take action to extend the lease term.

	Acres Expiring	
	Gross Acres	Net Acres
	(in thousands)	
Years Ending December 31:		
2013	2,684	1,533
2014	3,442	2,430
2015	2,243	1,360
After 2015 and other	7,054	3,964
Total[(a)]	15,423	9,287

(a) Includes held-by-production acreage 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

Marketing

Chesapeake Energy Marketing, Inc. (CEMI), one of our wholly owned subsidiaries, provides natural gas, oil and NGL marketing services, including commodity price structuring, contract administration and nomination services for Chesapeake, its joint working interest owners and other producers. We attempt to enhance the value of our natural gas and oil 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 for our production.

Our oil and NGL production is generally sold under market sensitive short-term or spot price contracts. Our natural gas 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 by the purchaser after transportation and processing of our natural gas. Under percentage-of-index contracts, the price per mmbtu we receive for our natural gas is tied to indices published in Inside FERC or Gas Daily. Although exact percentages vary daily, as of February 2013, approximately 80% of our natural gas production was primarily sold under short-term contracts at market-sensitive prices. Sales to Plains Marketing, L.P. represented 11% of our total revenues (before the effects of hedging) for the year ended December 31, 2012. There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the years ended December 31, 2011 and 2010.

Midstream Gathering Operations

Historically, Chesapeake 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. By doing so, we were better able to manage the value received for, and the costs of, gathering, treating and processing natural gas. These systems were designed primarily to gather the Company's 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. Chesapeake generated revenues from its gathering, treating and compression activities through various gathering rate structures. The Company also processed a portion of its natural gas at various third-party plants.

In December 2012, we sold the majority of our midstream business for proceeds of $2.160 billion, subject to post-closing adjustments, to Access Midstream Partners, L.P. (NYSE: ACMP). ACMP, formerly Chesapeake Midstream Partners, L.P., was an affiliate of ours from 2010 until we sold our investment in it during June 2012 for proceeds of $2.0 billion. See Note 11 and Note 12 of the notes to the consolidated financial statements included in Item 8 of this report for further discussion of these transactions.

Compression Operations

Since 2003, Chesapeake has built its compression business through its wholly owned subsidiary, MidCon Compression, L.L.C. (MidCon). MidCon operates wellhead and system compressors, with over 1.0 million horsepower of compression, to facilitate the transportation of natural gas primarily produced from Chesapeake-operated wells. In a series of transactions since 2007, MidCon sold 2,322 compressors (net of 231 repurchased units), a significant portion of its compressor fleet, and entered into a master lease agreement. These transactions were recorded as sales and operating leasebacks.

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 17 of the notes to our consolidated financial statements included in Item 8 of this report.

Oilfield Services

We formed Chesapeake Oilfield Services, L.L.C. (now COS Holdings, L.L.C.) (COS) in 2011 to own and operate our oilfield services assets. COS is a diversified oilfield services company that provides a wide range of well site services, primarily to Chesapeake and its working interest partners. COS focuses on providing services that are strategic to our operations, represent historical bottlenecks to our operations or that provide relatively high margins to the service provider. These services include contract drilling, hydraulic fracturing, oilfield rentals, rig relocation, fluid transportation and disposal and manufacturing of natural gas compressor packages. These services are fundamental to establishing and maintaining the flow of natural gas and oil throughout the productive life of a well. A source of liquidity for COS's business is the $500 million oilfield services revolving bank credit facility described under Liquidity and Capital Resources in Item 7 of this report. Additionally, in October 2011, Chesapeake Oilfield Operating, L.L.C. (COO), a wholly owned subsidiary of COS, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. Proceeds from this placement were used to make a cash distribution to its direct parent, COS, to enable it to reduce indebtedness under an intercompany note with Chesapeake. See Note 3 of the notes to the consolidated financial statements included in Item 8 of the report for further discussion of the revolving bank credit facility and senior notes.

Our oilfield services operations constitute a reportable segment under accounting guidance for disclosure about segments of an enterprise and related information. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report. COS conducts operations through five lines of business, as described below.

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Contract Drilling

Securing available rigs is an integral part of the exploration process, and therefore, owning our own drilling company, Nomac Drilling, L.L.C., is a strategic advantage for us. As of December 31, 2012, we had invested approximately $1.4 billion to build or acquire 119 drilling rigs, which are utilized primarily to drill Chesapeake-operated wells. In a series of transactions since 2006, our drilling subsidiaries have sold 68 drilling rigs (net of 26 repurchased rigs) and related equipment and subsequently leased back the rigs through 2018. These transactions were recorded as sales and operating leasebacks. The drilling rigs have depth ratings between 3,000 and 25,000 feet and range in drilling horsepower from 500 to 2,000. These drilling rigs are currently operating in Louisiana, Montana, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia and Wyoming. As of December 31, 2012, we had a fleet of 119 land drilling rigs and are the fifth largest land driller operating in the U.S.

Hydraulic Fracturing

In 2010, we began the process of building a hydraulic fracturing business under the name of Performance Technologies, L.L.C. (PTL). As part of that effort, we purchased two hydraulic fracturing fleets with an aggregate of 60,000 horsepower. As of December 31, 2012, we owned seven hydraulic fracturing fleets with an aggregate of 270,000 horsepower that provide hydraulic fracturing and other well stimulation services.

Oilfield Rentals

Our oilfield rentals business provides premium rental tools for land-based natural gas and oil drilling, completion and workover activities under the name Great Plains Oilfield Rental, L.L.C. We offer a full line of rental tools, including drill pipe, drill collars, tubing, blowout preventers, frac tanks and mud tanks and mud systems. We also provide air drilling and flowback services and services associated with the transfer of fresh water to the wellsite.

Oilfield Trucking

In 2006, we expanded our oilfield services by acquiring two privately owned oilfield trucking service companies. We now own one of the largest oilfield and heavy haul transportation companies in the industry under the names of Hodges Trucking Company, L.L.C. and Oilfield Trucking Solutions, L.L.C. Our trucks move drilling rigs, produced water, crude oil, other fluids and construction materials to and from the wellsite. As of December 31, 2012, we owned a fleet of 278 rig relocation trucks, 66 cranes and forklifts and 250 fluid service trucks.

Other Operations

Our other operations consist primarily of our natural gas compressor manufacturing business that operates under the name of Compass Manufacturing, L.L.C. in which we design, engineer, fabricate, install and sell natural gas compression units, accessories and equipment used in the production, treatment and processing of natural gas and oil. Once the compressors are complete, substantially all of the completed compressors are sold to MidCon.

Competition

We compete with both major integrated and other independent natural gas and oil 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 U.S. develops new energy and climate-related policies. In addition, some of our larger competitors may have a competitive advantage when responding to factors that affect demand for natural gas and oil 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 believe that our technological expertise, our exploration, land, drilling and production capabilities and the experience of our management generally enable us to compete effectively.

Hedging Activities

We utilize derivative strategies to manage the price of a portion of our future natural gas and oil production and to manage interest rate exposure. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Regulation

General

All of our operations are conducted onshore in the U.S. The U.S. natural gas and oil industry is regulated at the federal, state and local levels, and some of the laws, rules and regulations that govern our operations carry substantial administrative, civil and criminal penalties for non-compliance. Although we believe we are in substantial compliance with all applicable laws and regulations, and that remaining in substantial 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 impacts of compliance or non-compliance. Additional proposals and proceedings that affect the natural gas and oil industry are regularly considered by Congress, the states, the local governments, the courts and federal agencies, such as the U.S. Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission, the Department of Transportation, the Department of Interior and the Department of Energy. We actively monitor regulatory developments regarding our industry in order to anticipate and design required compliance activities and systems.

Exploration and Production Operations

The laws and regulations applicable to our exploration and production operations include requirements for permits 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 location of wells;
- the method of drilling and completing wells;
- the surface use and restoration of properties upon which wells are drilled;
- water withdrawal;
- the plugging and abandoning of wells;
- the recycling or disposal of fluids used or other substances handled in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Our operations may require us to obtain permits for, among other things,

- air emissions;
- construction activities, including in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- the construction and operation of underground injection wells to dispose of produced water and other non-hazardous oilfield wastes; and
- the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

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 provisions of our permits could result in revocation of such 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 natural gas and oil 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, Ohio, 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, state conservation laws establish maximum rates of production from natural gas and oil 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 natural gas and oil 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 December 2012, however, we sold substantially all of our midstream business, and we plan to sell most of our remaining midstream business in 2013. As a result, the impact on our business of compliance with the laws and regulations described below has decreased since the beginning of 2012 and will continue to diminish as we complete additional midstream sales.
In addition to the environmental, health and safety laws and regulations discussed below under Environmental, Health and Safety Matters, our midstream facilities are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation (DOT) pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA) and the Pipeline Safety Improvement Act of 2002 (PSIA) 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. The PSIA establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas. The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in “high consequence areas,” such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways.
We or the entities in which we own an interest inspect our pipelines regularly using equipment rented from third-party suppliers. Third parties also assist us in interpreting the results of the inspections.
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 authority and capacity to address pipeline safety. We do not anticipate that complying with applicable state laws and regulations will have a material adverse effect on our financial position, cash flows or results of operations. Our natural gas pipelines have inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.
Natural gas gathering and intrastate transportation facilities are exempt from the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act. Although the FERC has not made any 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. FERC regulation affects our gathering and compression business generally. The 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 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 or 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.

Oilfield Services Operations

Our oilfield services business operates under the jurisdiction of a number of regulatory bodies that regulate worker safety standards, the handling of hazardous materials, the transportation of explosives, the protection of the environment and driving standards of operation. Regulations concerning equipment certification create an ongoing need for regular maintenance that is incorporated into our daily operating procedures.

In providing trucking services, we operate as a motor carrier and therefore are subject to regulation by the DOT and various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety, financial reporting and certain mergers, consolidations and acquisitions. Interstate motor carrier operations are subject to safety requirements prescribed by the DOT and, to a large degree, intrastate motor carrier operations are subject to safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations, and DOT regulations mandate drug testing of drivers. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements.

The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service (HOS) regulations that govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size. From time to time, various legislative proposals are introduced, such as proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Environmental, Health and Safety Matters

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 connected with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- requiring investigatory and remedial actions to address pollution conditions caused by our operations or attributable to former operations;
- requiring noise mitigation, setbacks, landscaping, fencing, and other measures; and
- prohibiting the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations.

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, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by 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 and state levels to anticipate future regulatory requirements that might be imposed to reduce the costs of compliance with any such requirements. We also actively 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 material environmental, health and safety laws and regulations that relate to our business. We believe that we are in substantial 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, or RCRA, regulate hazardous and non-hazardous solid wastes. In the course of our operations, we generate petroleum hydrocarbon wastes such as 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.

Federal, state and local laws may also require us to remove or remediate previously disposed wastes or hazardous substances otherwise released into the environment, including wastes or hazardous substances disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations at contaminated areas, or to perform 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, or 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 responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and persons that disposed of or arranged for the disposal of hazardous substances at 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 to seek to recover from responsible classes of persons the costs of such actions.

Air Emissions

Our operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, and impose various 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 natural gas and oil 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. While these rules remain in effect, the Agency has announced that it will reexamine and reissue the rules over the next three years. 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. The EPA is also conducting a review of the National Ambient Air Quality Standards (NAAQS) for ozone that is expected to be completed in 2013.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. The placement of material into jurisdictional water or wetlands of the U.S. is prohibited, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers. 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. See Item 3. Legal Proceedings for a description of penalties paid by us recently in connection with CWA misdemeanor violations at a road construction site in West Virginia, as well as pending EPA orders for compliance under the CWA related to well pad and pond sites in West Virginia. Spill prevention, control and countermeasure requirements of federal laws 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.

The Oil Pollution Act of 1990 (OPA) establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. 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 U.S.

Hydraulic Fracturing

Vast quantities of natural gas, natural gas liquids and oil deposits exist in deep shale and other unconventional formations. It is customary in our industry to recover these resources from these deep formations through the use of hydraulic fracturing, combined with horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep underground formations using water, sand and other additives pumped under high pressure into the formation. As with the rest of the industry, we use hydraulic fracturing as a means to increase the productivity of almost every well that we drill and complete. These formations are generally geologically separated and isolated from fresh ground water supplies by thousands of feet of impermeable rock layers.

We follow applicable legal requirements for groundwater protection in our operations that are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). Furthermore, our well construction practices include 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.

Injection rates and pressures are monitored in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations are shut down if an abrupt change occurs to the injection pressure or annular pressure. These aspects of hydraulic fracturing operations are designed to eliminate a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations.

Hydraulic fracture stimulation requires the use of water. We use fresh water or recycled produced water in our fracturing treatments in accordance with applicable water management plans and laws. We strive to find alternative sources of water and reduce our reliance on fresh water resources. We have technical staff dedicated to the development of water recycling and re-use systems, and our Aqua Renew® program uses state-of-the-art technology in an effort to recycle produced water in our operations.

Produced water is a by-product of natural gas and liquids extraction, regardless of whether hydraulic fracturing technology is used. Except for produced water we recycle and reuse, Chesapeake disposes of produced water in Class II underground injection control wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. These Class II wells are overseen by the EPA in its Underground Injection Control (UIC) Program. For some of our operations, EPA has delegated its UIC Program authority to a state environmental agency.

Some states have adopted, and other states are considering adopting, regulations that impose disclosure requirements on hydraulic fracturing operations. Since early 2011, we have voluntarily participated in FracFocus, a national publicly accessible web-based registry developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, with support of the U.S. Department of Energy, to report on a well-by-well basis the additives and chemicals and amount of water used in the hydraulic fracturing process for each of the wells we operate. The website, www.fracfocus.org, also includes information about how hydraulic fracturing works, the chemicals used in hydraulic fracturing and how fresh water aquifers are protected. Some states, such as Texas, Colorado, Montana, Louisiana and North Dakota, which mandate disclosure of chemical additives used in hydraulic fracturing require operators to use the FracFocus website for reporting.

Legislative, regulatory and enforcement efforts, as well as guidance from regulatory agencies, at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Hydraulic fracturing is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Safe Drinking Water Act's UIC Program and has released draft guidance documents regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. While we believe that the draft guidance, if adopted as final guidance, would not materially affect our operations because we do not use diesel fuel in connection with our hydraulic fracturing, we cannot predict the scope of the final guidance. The EPA also has commenced a study of the potential impacts of hydraulic fracturing activities on drinking water resources, with a progress report released in late 2012 and a final draft report expected to be released for public comment and peer review in late 2014. In addition, the Bureau of Land Management (BLM) has announced its intention to publish, in the first quarter of 2013, a revised draft of proposed rules that would impose new requirements on hydraulic fracturing operations conducted on federal lands, including the disclosure of chemical additives used. The results of EPA's guidance, including its definition of diesel fuel, EPA's study, BLM's proposed rules, and other analyses by federal and state agencies to assess the impacts of hydraulic fracturing could each 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 liquids and natural gas 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 substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity could materially limit or delay our plans. For example, as a result of a settlement reached in 2011, the U.S. Fish and Wildlife Service has published a work plan for listing more than 450 species over the next several years. Some of these species are included in the list of over 100 species that are currently proposed for listing as endangered or threatened species. In addition, the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

Global Warming and Climate Change

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. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the natural gas and oil 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.

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 natural gas and oil 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 natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time which result in litigation.

Operating Hazards and Insurance

The natural gas and oil 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 $425 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. 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. The insurance coverage that we maintain 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 or administrative offices in approximately 110 cities or towns in the areas where we conduct our operations.

Executive Officers

Aubrey K. McClendon, President and Chief Executive Officer

Aubrey K. McClendon, 53, has served as Chief Executive Officer since co-founding the Company in 1989 and President since June 2012. Mr. McClendon previously served as Chairman of the Board from 1989 to June 2012. Mr. McClendon served as a director of the general partner of Access Midstream Partners, L.P. (NYSE:ACMP), formerly Chesapeake Midstream Partners, L.P., from January 2010 to June 2012. On January 29, 2013, Mr. McClendon agreed to retire from the Company, effective no later than April 1, 2013.

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

Domenic J. (“Nick”) Dell'Osso, Jr., 36, has served as Executive Vice President and Chief Financial Officer since November 2010. Mr. Dell'Osso has also served as a director of the general partner of ACMP since June 2011. 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.

Steven C. Dixon, Executive Vice President - Operations and Geosciences and Chief Operating Officer

Steven C. Dixon, 54, has served as Executive Vice President - Operations and Geosciences and Chief Operating Officer since February 2010. Mr. Dixon served as Executive Vice President-Operations and Chief Operating Officer from 2006 to February 2010 and as Senior Vice President - Production from 1995 to 2006. He also served as Vice President-Exploration from 1991 to 1995.

Jeffrey A. Fisher, Executive Vice President - Production

Jeffrey A. Fisher, 53, has served as Executive Vice President - Production since December 2012. He served as Senior Vice President - Production from 2006 to December 2012. Mr. Fisher served as Vice President - Operations for the Company's Southern Division from 2005 to 2006 and served as Operations Manager from 2003 to 2005.

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

Douglas J. Jacobson, 59, has served as Executive Vice President - Acquisitions and Divestitures since 2006. He served as Senior Vice President - Acquisitions and Divestitures from 1999 to 2006.

Martha A. Burger, Senior Vice President - Human and Corporate Resources

Martha A. Burger, 60, has served as Senior Vice President - Human and Corporate Resources since 2007. She served as Treasurer from 1995 to 2007 and as Senior Vice President - Human Resources since 2000. She was the Company's Vice President - Human Resources from 1998 until 2000, Human Resources Manager from 1996 to 1998 and Corporate Secretary from 1999 to 2000. From 1994 to 1995, she served in various accounting positions with the Company, including Assistant Controller - Operations.

Jennifer M. Grigsby, Senior Vice President, Treasurer and Corporate Secretary

Jennifer M. Grigsby, 44, has served as Senior Vice President and Treasurer since 2007 and as Corporate Secretary since 2000. She served as Vice President from 2006 to 2007 and as Assistant Treasurer from 1998 to 2007. From 1995 to 1998, Ms. Grigsby served in various accounting positions with the Company.

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Michael A. Johnson, Senior Vice President - Accounting, Controller and Chief Accounting Officer
Michael A. Johnson, 47, 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.
James R. Webb, Senior Vice President - Legal and General Counsel
James R. Webb, 45, has served as Senior Vice President - Legal and General Counsel since October 2012. Prior to joining the Company, Mr. Webb was an attorney with the law firm of McAfee & Taft from February 1995 to October 2012.
Other Senior Officers
Henry J. Hood, Senior Vice President - Land
Henry J. Hood, 52, has served as Senior Vice President - Land since June 2012. He served as Senior Vice President - Land and Legal from 1997 to 2012 and as Vice President - Land and Legal from 1995 to 1997. He also served as General Counsel from April 2006 to June 2012.
James C. Johnson, Senior Vice President -Marketing
James C. Johnson, 55, has served as President of Chesapeake Energy Marketing, Inc., a wholly-owned subsidiary of the Company, and as Senior Vice President - Marketing of the Company since 2000. He served as Vice President - Contract Administration for the Company from 1997 to 2000 and as Manager - Contract Administration from 1996 to 1997.
John M. Kapchinske, Senior Vice President - Geoscience
John M. Kapchinske, 62, has been Senior Vice President - Geoscience since June 2011. He served as Vice President - Geoscience from 2005 to May 2011 and Geoscience Manager from 2001 to 2004.
Stephen W. Miller, Senior Vice President - Drilling
Stephen W. Miller, 56, has served as Senior Vice President - Drilling since 2001. He served as Vice President -Drilling from 1996 to 2001 and as District Manager - College Station District from 1994 to 1996.
Jeffrey L. Mobley, Senior Vice President - Investor Relations and Research
Jeffrey L. Mobley, 44, has served as Senior Vice President - Investor Relations and Research since 2006 and was Vice President - Investor Relations and Research from 2005 to 2006.
Thomas S. Price, Jr., Senior Vice President - Corporate Development and Government Relations
Thomas S. Price, Jr., 61, has served as Senior Vice President - Corporate Development and Government Relations since March 2009. He served as Senior Vice President - Corporate Development from 2005 to March 2009 and as Senior Vice President - Investor and Government Relations from 2003 to 2005, Senior Vice President - Corporate Development from 2000 to 2003, Vice President - Corporate Development from 1992 to 2000.
Cathlyn L. Tompkins, Senior Vice President - Information Technology and Chief Information Officer
Cathlyn L. Tompkins, 52, 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.
Jerry L. Winchester, Senior Vice President - Oilfield Services and Chief Executive Officer of Chesapeake Oilfield Services
Jerry L. Winchester, 54, has served as Chief Executive Officer of Chesapeake Oilfield Services, L.L.C., our oilfield services subsidiary, since September 2011 and as Senior Vice President - Oilfield Services of the Company since November 2011. From November 2010 to September 2011, Mr. Winchester served as the Vice President - Boots & Coots of Halliburton. From July 2002 to September 2010, Mr. Winchester served as the President and Chief Executive Officer of Boots & Coots International Well Control, Inc. (“Boots & Coots”), an NYSE-listed oilfield services company specializing in providing integrated pressure control and related services.

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Employees

Chesapeake had approximately 12,000 employees as of December 31, 2012. This number does not include approximately 1,250 midstream employees that became ACMP employees effective January 1, 2013 as a result of the sale of substantially all of our midstream business. See Note 11 of our consolidated financial statements included in Item 8 of this report for further discussion of our midstream business divestitures.

Glossary of Natural Gas and Oil 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.

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.

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

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas, oil 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 Hole; Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as a natural gas or oil 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 natural gas or oil 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.

Horizontal Wells. Wells drilled at angles greater than 70 degrees from vertical.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of natural gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalent.

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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 natural gas, oil and NGL reserves.
Present Value or PV-10. When used with respect to natural gas, oil 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 natural gas and oil 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 natural gas, oil or NGL received at the sales point and the New York Mercantile Exchange (NYMEX).
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 natural gas and oil reserves are those quantities of natural gas and oil, 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 natural gas or oil on the basis of available geoscience and engineering data. In the absence of information 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 such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved Undeveloped Reserves. 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 the 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 such 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.

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table located in Note 10 of the notes to our consolidated financial statements included in Item 8 of this report. Management uses the reserve replacement ratio as an indicator of the Company's ability to replenish annual production volumes and grow its reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

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 natural gas and oil property entitling the owner to a share of natural gas, oil 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.

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of natural gas equivalent.

Unconventional. Plays found within regional pervasive formations with low matrix permeability and close association with hydrocarbon source rocks.

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

Unproved Properties. Properties with no proved reserves.

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

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

ITEM 1A. Risk Factors

Natural gas, oil 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 the natural gas, oil and NGL we sell. We require substantial expenditures to replace reserves, sustain production and fund our business plans. Lower natural gas, oil 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 natural gas and oil properties. We urge you to read the risk factors below for a more detailed description of each of these risks.

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

- domestic and worldwide supplies of natural gas, oil and NGL, including U.S. inventories of natural gas and oil 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;
- 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 gas producing regions; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty. In the U.S., record-high supplies of natural gas and weak demand during 2012 resulted in natural gas prices at 10-year lows in early 2012, and while prices have risen from their lows, they remain depressed.

Further, the prices of natural gas, oil and NGL have not moved in tandem in recent years, creating a value gap that has caused us to shift our focus from dry gas plays to liquids-rich plays. In 2012, oil and NGL production accounted for only 20% of our total production but 59% of our revenue, including the effects of realized hedging, and we anticipate that approximately 60% of our 2013 revenue will come from our oil and NGL production, based on current NYMEX strip prices and our current hedging positions. Nevertheless, natural gas prices can significantly affect our future results as approximately 70% of our estimated proved reserves at December 31, 2012 were natural gas. A substantial or extended decline in natural gas, oil or NGL prices could negatively affect future revenue and the quantities of natural gas, oil and NGL reserves that may be economically produced. Even with natural gas and oil derivatives currently in place for our future production (85% of our forecasted 2013 oil production through swaps and written call options and 50% of our forecasted 2013 natural gas production through swaps and three-way collars), our revenue and results of operations will be partially exposed to changes in future commodity prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2012, we had long-term indebtedness of approximately $12.620 billion and unrestricted cash of $287 million, and our net indebtedness represented 41% of our total book capitalization, which we define as the sum of total equity and total current and long-term debt less unrestricted cash. We had $418 million of outstanding borrowings drawn under our oilfield services revolving bank credit facility and no outstanding borrowings under our corporate revolving bank credit facility as of December 31, 2012.

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;
- the oilfield services revolving bank credit facility and the indenture governing the COO 6.625% Senior Notes due 2019 restrict the payment of dividends or distributions to Chesapeake;
- additional financing 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 corporate revolving bank credit facility.

The borrowing base of our corporate revolving bank credit facility is subject to periodic redetermination and is based in part on natural gas and oil prices. A lowering of our borrowing base because of lower natural gas and oil prices or for other reasons could require us to repay indebtedness in excess of the borrowing base, or we might need to further secure the lenders with additional collateral. 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. General economic conditions, natural gas, oil and NGL prices and financial, business and other factors affect our operations and our future performance and many of these factors are beyond our control. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital. In addition, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness. We would have been unable to meet the leverage ratio maintenance covenant of our corporate revolving bank credit agreement at September 30, 2012 and had to obtain an amendment of that covenant to remain in compliance. Our lenders may not agree to an amendment or waiver of any other potential future covenant default. A default under the corporate revolving bank credit facility could result in 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 anticipate completing asset sales in 2013 and intend to apply a portion of the proceeds from such sales to reduce our overall level of indebtedness. If we are unable to consummate such sales or if they do not generate the proceeds we are anticipating, we would be required to reduce our capital spending, or seek to identify, pursue and obtain funds from other sales transactions or other sources in order to meet our operating, capital spending and debt reduction plans.

Declines in the prices of natural gas and oil could result in a write-down of our asset carrying values.

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ending in the quarter, adjusted for the

impact of derivatives accounted for as cash flow hedges. We are required to write down the carrying value of our natural gas and oil assets if capitalized costs exceed the ceiling limit, and such write-downs can be material.

The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low. Natural gas prices declined significantly in late 2011 and 2012 to the lowest level in recent years and while prices have risen from their lows, they remain depressed. As a result, our financial statements for the year ended December 31, 2012 reflect an impairment of approximately $3.315 billion recorded in the 2012 third quarter with respect to our natural gas and oil properties. Sustained low natural gas prices and other factors could cause us to be required to write down our natural gas and oil properties or other assets in the future and incur a non-cash charge against future earnings.

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

Our exploration, development and acquisition activities and our oilfield services businesses require substantial capital expenditures and we plan to make capital expenditures in 2013 that exceed our estimated 2013 cash flows from operations. Thus, we intend to fund our capital expenditures through a combination of cash flows from operations and borrowings under our corporate and oilfield services revolving bank credit facilities and, to the extent those sources are not sufficient, from debt and equity issuances, other financings and asset sales. 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 natural gas and oil, our success in developing and producing new reserves and the other risk factors discussed herein. Our ability to obtain capital from other sources, such as the capital markets, other financings and asset sales, is dependent upon many of those same factors as well as the orderly functioning of credit and capital markets. If such proceeds are inadequate to fund our planned spending, we would be required to reduce our capital spending, seek to sell different or additional assets or pursue other funding alternatives, and we could have a reduced ability to replace our reserves and increase liquids production.

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 natural gas and oil 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 43% of our total estimated proved reserves (by volume) as of December 31, 2012 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Our reserve estimates at December 31, 2012 reflected a decline in the production rate on producing properties of approximately 33% in 2013 and 22% in 2014. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities and present value of our proved reserves may be different than we have estimated.

This report 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 natural gas, oil and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas, oil 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, natural gas, oil and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, oil 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 natural gas and oil prices and other factors, many of which are beyond our control.

At December 31, 2012, approximately 43% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflect our plans to make significant capital expenditures to convert our proved undeveloped reserves (PUDs) into proved developed reserves, including approximately $12.0 billion during the five years ending in

2017. You should be aware that the estimated development costs may not be accurate, 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.

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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 write off 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 natural gas and oil 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, 2012 present value is based on $2.76 per mcf of natural gas and $94.84 per barrel of oil before price differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

Any changes in consumption by natural gas, oil and NGL purchasers or in governmental regulations or taxation will also affect the actual future net cash flows from our production.

The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. 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 accurate discount factor. The effective interest rate at various times and the risks associated with our business or the natural gas and oil industry in general will affect the accuracy 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 unproved property in order to further our development efforts. 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 unproved properties and leased undeveloped acreage 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 unproved property acquired by us or undeveloped acreage leased 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 unproved property or wells.

Drilling for natural gas and oil 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 operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas and oil, costs associated with producing natural gas, oil 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 identifying unproved property prospects 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 unproved property, leasing of undeveloped acreage or drilling a well, whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies. Drilling results in our newer natural gas and liquids-rich unconventional plays may be more uncertain than in unconventional plays that are more developed and have longer established production histories; meanwhile drilling and completion techniques that have proven to be successful in other unconventional formations to maximize recoveries may be unsuccessful when used in new unconventional formations.

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 natural gas and oil 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. While we seek to actively manage our leasehold inventory using our drilling rig fleet and oilfield services to drill sufficient wells to hold the leasehold that we believe is material to our operations, our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas and oil 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.

Our hedging activities may reduce the realized prices we receive for our natural gas, oil and NGL sales, require us to provide collateral for hedging 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 natural gas and oil price risk management arrangements for a portion of our expected production. Commodity price derivatives may limit the prices we actually realize and therefore reduce natural gas, oil and NGL revenues in the future. Our commodity hedging 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 natural gas and oil 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. Although the counterparties to our multi-counterparty secured hedging facility are required to secure their hedging obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the hedging 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. The risk of counterparty default is heightened in a poor economic environment.

Most of our natural gas and oil derivative contracts are with the 17 counterparties to our multi-counterparty hedging facility. Our obligations under the facility are secured by natural gas and oil 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, 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 natural gas and oil 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 natural gas and oil prices.

Natural gas and oil drilling and producing operations can be hazardous and may expose us to liabilities, including environmental liabilities.

Natural gas and oil operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our prospects. If any of these risks occurs, we could sustain substantial losses as a result of:

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

There is inherent risk of incurring significant environmental costs and liabilities in our operations due to our use, generation, handling and disposal of materials, including wastes, petroleum hydrocarbons and other chemicals. We may incur joint and several, strict liability under applicable U.S. federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leased or owned properties resulting from current or historical operations. In some cases our properties have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under our control. We also could incur material fines, penalties and government or third-party claims as a result of violations of, or liabilities under, applicable environmental laws and regulations. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance. While we may maintain insurance against some, but not all, of the risks

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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.

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

It is customary in our industry to recover natural gas and oil from deep shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep formations using water, sand and other additives pumped under high pressure into the formation. We use hydraulic fracturing as a means to increase the productivity of almost every well that we drill and complete.

The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states, including Pennsylvania, Texas, Colorado, Montana, Ohio, New Mexico and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. New York has placed a permit moratorium on high volume fracturing activities combined with horizontal drilling pending the results of a study regarding the safety of hydraulic fracturing. 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.

Additionally, the EPA has asserted federal regulatory authority over hydraulic fracturing activities involving diesel fuel (specifically, when diesel fuel is utilized in the stimulation fluid) under the Safe Drinking Water Act and is drafting guidance documents related to this newly asserted regulatory authority. 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. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities.

Certain environmental and other groups have 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 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 through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Federal regulatory initiatives relating to air emissions could result in increased costs and additional operating restrictions or delays.

The EPA has published New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amended existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and gas production, transmission and distribution facilities. The Agency has indicated that it will reexamine and reissue these rules over the next three years, but the outcome of this process remains uncertain. In addition, the EPA has issued rules requiring 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 these rules, but the outcome of the challenge is uncertain and may impact our reporting obligations. The EPA is also conducting a review of the National Ambient Air Quality Standards (NAAQS) for ozone, which is expected to be completed in 2013 and could result in more stringent air emissions standards applicable to our operations.

Federal regulatory initiatives relating to the protection of threatened or endangered species could result in increased costs and additional operating restrictions or delays.

The designation of previously unidentified endangered or threatened species pursuant to the ESA in areas where we intend to conduct construction activity could materially limit or delay our plans. For example, 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. Some of these species are included in the list of over 100 species that are currently proposed for listing as endangered or threatened species. In addition, the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

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Potential legislative and regulatory actions could increase our costs, reduce our revenue and cash flow from natural gas and oil sales, reduce our liquidity or otherwise alter the way we conduct our business.

The activities of exploration and production companies operating in the U.S. are subject to extensive regulation at the federal, state and local levels. Changes to existing laws and regulations or new laws and regulations such as those described below could, if adopted, have an adverse effect on our business.

Federal Taxation of Independent Producers

Recent federal budget proposals would potentially increase and accelerate the payment of federal income taxes of independent producers of natural gas and oil. 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. These changes, if enacted, will make it more costly for us to explore for and develop our natural gas and oil resources.

OTC Derivatives Regulation

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 swaps 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 protection hedging program related to the natural gas and oil we produce to manage the risk of low commodity prices and to predict with greater certainty the cash flow from our hedged production. We have used the OTC market exclusively for our natural gas and oil derivative contracts. 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 and negatively affect our revenues and cash flow during periods of low commodity prices.

Climate Change

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. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the natural gas and oil 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 could reduce demand for natural gas and oil.

The current worldwide economic uncertainty may have a material adverse effect on our results of operations, liquidity and financial condition.

The recovery from the global economic crisis of 2008 and resulting recession has been slow and uneven. Continuing concerns regarding the worldwide economic outlook and sovereign debt crisis in Europe have contributed to increased economic uncertainty and diminished expectations for the global economy. A slowdown in the current economic recovery or a return to a recession would negatively impact demand for petroleum products and prices for natural gas, oil and NGL. These circumstances could adversely impact our results of operations, liquidity and financial condition.

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Our cash flow from operations, our revolving bank credit facilities and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and asset sales to provide us with additional capital. Poor economic conditions may negatively affect:

- our ability to access the capital markets at a time when we would like, or need, to raise capital;
- the number of participants in our proposed asset sales transactions or the values we are able to realize in those transactions, making them uneconomic or harder or impossible to consummate;
- the collectability of our trade receivables if our counterparties are unable to perform their obligations or seek bankruptcy protection; or
- the ability of our joint venture partners to meet their obligations to fund a portion of our drilling costs under our joint venture agreements.

Our operations may be adversely affected by oilfield services shortages, pipeline and gathering system capacity constraints and various transportation interruptions.

From time to time, we experience delays in drilling and completing our natural gas and oil wells. In developing plays, the demand for equipment such as pipe and compressors can exceed the supply, and it is challenging to attract and retain qualified oilfield workers. Delays in developing our natural gas and oil assets for these and other reasons could negatively affect our revenues and cash flow.

In certain natural gas and liquids-rich 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 natural gas, oil and NGL gathering demand following the sale of substantially all of our midstream business in 2012. 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 natural gas, oil and NGL. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas, oil 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 natural gas, oil and NGL production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of 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, an action we took in 2012. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

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

The Company and current and former directors and officers are the subject of a number of shareholder lawsuits, and there are ongoing governmental and regulatory investigations and inquiries. The Company cannot predict the outcome or impact of these pending matters, but the lawsuits could result in judgments against the Company and directors and officers named as defendants and there could be one or more enforcement actions in respect of the governmental investigations. For example, we could be exposed to enforcement or other actions with respect to the continuing SEC investigation into certain disclosure, accounting and financial reporting matters. Our legal expenses increased in 2012 compared to 2011 due primarily to defending the shareholder lawsuits, responding to governmental investigations and inquiries, and conducting the Board's review of certain matters involving our Chief Executive Officer, and such expenses in the future may be significant. In addition, 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.

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 natural gas, oil 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 operation. 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.

We are currently involved in a search for a new CEO and if this search is delayed or if we were to lose the services of other key personnel, our business could be negatively impacted.

On January 29, 2013, Aubrey K. McClendon, our President, Chief Executive Officer (CEO) and a director, agreed with the Board of Directors to retire from the Company. Mr. McClendon will continue to serve as CEO, President and a director until the earlier of April 1, 2013 or the time at which his successor is appointed. To the extent there is a delay in choosing a new CEO, the Company's business could be negatively impacted. In addition, our future success depends in part upon the continued service of key members of our senior management team. Our senior management team is critical to the overall management of the Company and they also play a key role in maintaining our culture and setting our strategic direction. All of our executive officers and key employees are at-will employees. The loss of key personnel could seriously harm our business.

We rely on highly skilled personnel and, if we are unable to retain or motivate key personnel, hire qualified personnel, or maintain our corporate culture, our operations may be negatively impacted.

Our performance largely depends on the talents and efforts of highly skilled individuals. Our future success depends on our continuing ability to identify, hire, develop, motivate, and retain highly skilled personnel for all areas of our organization. Competition in our industry for qualified employees is intense, and certain of our competitors have directly targeted our employees. In addition, our compensation arrangements may not always be successful in attracting new employees and retaining and motivating our existing employees. Our continued ability to compete effectively depends on our ability to attract new employees and to retain and motivate our existing employees. In addition, we believe that our corporate culture fosters innovation, creativity, and teamwork. We believe that our ability to maintain our corporate culture is an important component of our future success.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

Information regarding our properties is included in Item 1 and in Note 10 of the notes to our consolidated financial statements included in Item 8 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 an indeterminate amount of damages. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.

July 2008 Common Stock Offering. 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. Following the appointment of a lead plaintiff and counsel, 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. On September 2, 2010, the court denied the defendants’ motion to dismiss, and the court certified the class on March 30, 2012. Defendants moved for summary judgment on grounds of loss causation and materiality on December 16, 2011, and the motion was fully briefed as of

August 21, 2012. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. On October 22, 2012, the court issued an order staying the derivative action until resolution of the federal class action. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the Company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. On November 30, 2011, the Company filed a motion to dismiss the action, which was denied on September 28, 2012. Pursuant to court order, nominal defendant Chesapeake filed an answer on October 12, 2012. By stipulation between the parties, the individual defendants are not required to answer the complaint unless and until the plaintiff establishes standing to pursue claims derivatively.

2008 CEO Compensation and Related Party Transaction. Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7 and May 20, 2009 against the Company's directors alleging, among other things, breaches of fiduciary duties relating to the 2008 compensation of the Company's CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. Chesapeake's motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011. The appeal is currently stayed pending resolution of the settlement referenced in the following paragraph.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved a settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with Mr. McClendon. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company approximately $12 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs' counsel in the amount of $3.75 million. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants. On February 29, 2012, certain shareholders filed a petition in error with the Oklahoma Supreme Court opposing the terms of the settlement. Their appeal was fully briefed as of October 24, 2012.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the Company's current and former directors, two shareholders alleged that the Chesapeake Board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon's 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and on March 14, 2012 were stayed until 30 days after the Supreme Court of Oklahoma resolves the appeal of the settlement of the consolidated derivative action and books and records action.

FWPP, Conflict of Interest and Other Matters. From April 19 to June 29, 2012, 13 substantially similar shareholder derivative actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company and its directors alleging, among other things, violations of Section 14 of the Securities Exchange Act of 1934 and Rule 14a-9 promulgated thereunder for purported material misstatements in the Company's 2009 and subsequent proxy statements related to Mr. McClendon's participation in the Founder Well Participation Program (FWPP) and breaches of fiduciary duties, corporate waste, and unjust enrichment against the Board for failing to make proper disclosures in the proxy statements and failing to properly monitor Mr. McClendon's personal use of assets acquired pursuant to the FWPP. As described in Note 6, in conjunction with Mr. McClendon's employment agreement with the Company, the FWPP provides Mr. McClendon a contractual right through June 2014 to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company's leasehold. On July 13, 2012, these 13 shareholder actions were consolidated into a single case. On April 27, 2012, a shareholder derivative action was filed in the District Court of Oklahoma County, Oklahoma setting forth substantially similar claims to those alleged in the federal shareholder actions. Plaintiffs in both the federal consolidated derivative action and the state court derivative action stipulated to stay their cases pending a ruling on the motion to dismiss filed in the federal securities class action described in the following paragraph. On February 6, 2013, another shareholder derivative suit was filed in the District Court of Oklahoma County, Oklahoma asserting claims substantially similar to those of the stayed derivative cases and seeking a temporary restraining order barring the Company from providing Mr. McClendon severance compensation and benefits. The hearing for the restraining order is set for March 29, 2013.

A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and Mr. McClendon alleging violations of Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserts claims under Sections 10(b) (and Rule 10b-5) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company's asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon's personal loans and the Company's internal controls. The action seeks class certification, damages of an unspecified amount and attorneys' fees and other costs. The Company and other defendants filed a motion to dismiss the action on December 6, 2012, and the plaintiff filed its response on January 23, 2013. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

On June 19, July 17 and July 20, 2012, putative class actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company, Chesapeake Energy Savings and Incentive Stock Bonus Plan (the Plan), and certain of the Company’s officers and directors alleging breaches of fiduciary duties under the Employee Retirement Income Security Act (ERISA). The actions are brought on behalf of participants and beneficiaries of the Plan, and allege that as fiduciaries of the Plan, defendants owed fiduciary duties, which they purportedly breached by, among other things, failing to manage and administer the Plan’s assets with appropriate skill and care, failing to disclose material information concerning such matters as Mr. McClendon’s participation in the FWPP and his related financing arrangements and the Company’s VPP transactions, engaging in activities that were in conflict with the best interest of the Plan, and permitting the Plan to over-concentrate in Chesapeake stock. The plaintiffs seek class certification, damages of an unspecified amount, equitable relief, and attorneys’ fees and other costs. The three cases have been consolidated, and a consolidated amended complaint was filed on February 21, 2013. Defendants have 60 days from that date in which to respond. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

On May 2, 2012, Chesapeake and Mr. McClendon received notice from the U.S. Securities and Exchange Commission that its Fort Worth Regional Office had commenced an informal inquiry into, among other things, certain of the matters alleged in the foregoing lawsuits. On December 21, 2012, the SEC's Fort Worth Regional Office advised Chesapeake that its inquiry is continuing as an investigation, and it has issued subpoenas for information and testimony. The Company, including Mr. McClendon, is providing information to the SEC in connection with this matter. The Company is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations.

Director and Officer Use of Company Aircraft. On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company’s directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company’s officers and directors’ use of the Company’s fractionally owned corporate jets. Chesapeake was named a nominal defendant in the derivative action. On August 21, 2012, the District Court granted the Company's motion to dismiss the case. On December 6, 2012, the plaintiff filed an amended petition in error with the Oklahoma Supreme Court, and on December 26, 2012 nominal defendant/appellee Chesapeake filed its response. The appeal is currently before the Oklahoma Court of Appeals by appointment of the Supreme Court.

Antitrust Investigations. On June 29, 2012, Chesapeake received a subpoena duces tecum from the Antitrust Division, Midwest Field Office of the U.S. Department of Justice. The subpoena requires the Company to produce certain documents before a grand jury in the Western District of Michigan, which is conducting an investigation into possible violations of antitrust laws in connection with the purchase and lease of oil and gas rights. The Company has also received demands for documents and information from certain state governmental agencies in connection with other investigations relating to the Company’s purchase and lease of oil and gas rights. Chesapeake has been providing information in response to these investigations. Chesapeake's Board of Directors commenced its own investigation of these allegations in June 2012 and has recently announced the results. See Recent Developments in Item 7 of this report for further discussion.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, 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 natural gas and oil 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 cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal. As of December 31, 2012, we have increased natural gas and oil properties by $127 million for three specific performance cases which would require us to acquire natural gas and oil interests. Of this amount, $104 million relates to a judgment entered in July 2012 against us in an action for specific performance of 2008 contracts to purchase natural gas and oil properties. We are also recording interest on the judgment. The original trial court's holding that the contracts were not enforceable was reversed on appeal. The Company has posted a supersedeas bond to stay enforcement of the judgment and has filed a motion for new trial and/or to alter or amend the judgment. Based on management’s current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to the Company’s business operations is likely to have a material adverse effect on its consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management’s estimates.

Environmental Risk

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

There are presently pending against our subsidiary, Chesapeake Appalachia, L.L.C. (CALLC), orders for compliance first initiated in the 2010 fourth quarter by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia. We have responded to all pending orders and are actively working with the EPA to resolve these matters. For one site subject to an EPA order for compliance, CALLC pled guilty in the U.S. District Court for the Northern District of West Virginia on October 5, 2012, to three misdemeanor counts of unauthorized discharge of dredge or fill materials into a water of the U.S. On December 3, 2012, CALLC was sentenced to a two-year probation term and a fine of $200,000 for each misdemeanor, for a total fine of $600,000. We have paid the fine in full and believe that we are in material compliance with the terms of probation.

The CWA provides authority for significant civil penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation. The CWA sets forth subjective criteria, including degree of fault and history of prior violations, that influence CWA penalty assessments, and the EPA may also seek to recover the economic benefit derived from non-compliance. While we expect that resolution of the EPA’s orders for compliance will include monetary sanctions exceeding $100,000, we believe the liability with respect to these matters will not have a material effect on the consolidated financial position, results of operations or cash flow of the Company.

ITEM 4. Mine Safety Disclosures

Not applicable.

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PART II. OTHER INFORMATION

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, 2012:			
Fourth Quarter	$21.66	$16.23	$0.0875
Third Quarter	$20.64	$16.62	$0.0875
Second Quarter	$23.69	$13.32	$0.0875
First Quarter	$26.09	$20.41	$0.0875
Year Ended December 31, 2011:			
Fourth Quarter	$29.87	$22.00	$0.0875
Third Quarter	$35.75	$25.54	$0.0875
Second Quarter	$34.70	$27.28	$0.0875
First Quarter	$35.95	$25.93	$0.0750

At February 12, 2013, there were approximately 2,250 holders of record of our common stock and approximately 375,500 beneficial owners.

While 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 corporate revolving bank 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.

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Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents information about repurchases of our common stock during the quarter ended December 31, 2012:

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 Number of Shares That May Yet Be Purchased Under the Plans or Programs[b]
October 1, 2012 through October 31, 2012	57,465	$19.86	—	—
November 1, 2012 through November 30, 2012	14,416	$17.34	—	—
December 1, 2012 through December 31, 2012	409,053	$16.66	—	—
Total	480,934		—	—

(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.

(b) We make matching contributions to our 401(k) plan and deferred compensation plan using Chesapeake common stock that is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of Company contributions.

ITEM 6. Selected Financial Data

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2012, 2011, 2010, 2009 and 2008. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. 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, appearing in Items 7 and 8, respectively, of this report.

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	($ in millions, except per share data)				
REVENUES:					
Natural gas, oil and NGL	$6,278	$6,024	$5,647	$5,049	$7,858
Marketing, gathering and compression	5,431	5,090	3,479	2,463	3,598
Oilfield services	607	521	240	190	173
Total Revenues	12,316	11,635	9,366	7,702	11,629
OPERATING EXPENSES:					
Natural gas, oil and NGL production	1,304	1,073	893	876	889
Production taxes	188	192	157	107	284
Marketing, gathering and compression	5,312	4,967	3,352	2,316	3,505
Oilfield services	465	402	208	182	143
General and administrative	535	548	453	349	377
Natural gas, oil and NGL depreciation, depletion and amortization	2,507	1,632	1,394	1,371	1,970
Depreciation and amortization of other assets	304	291	220	244	174
Impairment of natural gas and oil properties	3,315	—	—	11,000	2,800
Net (gains) losses on sales of fixed assets	(267)	(437)	(137)	38	—
Impairments of fixed assets and other	340	46	21	130	30
Employee retirement and other termination benefits	7	—	—	34	—
Total Operating Expenses	14,010	8,714	6,561	16,647	10,172
INCOME (LOSS) FROM OPERATIONS	(1,694)	2,921	2,805	(8,945)	1,457
OTHER INCOME (EXPENSE):					
Interest expense	(77)	(44)	(19)	(113)	(271)
Earnings (losses) on investments	(103)	156	227	(39)	(38)
Gains on sales of investments	1,092	—	—	—	—
Losses on purchases or exchanges of debt	(200)	(176)	(129)	(40)	(4)
Impairments of investments	—	—	(16)	(162)	(180)
Other income (expense)	8	23	16	11	27
Total Other Income (Expense)	720	(41)	79	(343)	(466)
INCOME (LOSS) BEFORE INCOME TAXES	(974)	2,880	2,884	(9,288)	991
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes	47	13	—	4	423
Deferred income taxes	(427)	1,110	1,110	(3,487)	(36)
Total Income Tax Expense (Benefit)	(380)	1,123	1,110	(3,483)	387
NET INCOME (LOSS)	(594)	1,757	1,774	(5,805)	604
Net income attributable to noncontrolling interests	(175)	(15)	—	(25)	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(769)	1,742	1,774	(5,830)	604
Preferred stock dividends	(171)	(172)	(111)	(23)	(33)
Loss on conversion/exchange of preferred stock	—	—	—	—	(67)
NET INCOME (LOSS) AVAILABLE TO	$(940)	$1,570	$1,663	$(5,853)	$504

COMMON STOCKHOLDERS
STATEMENT OF OPERATIONS DATA (continued):

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	($ in millions, except per share data)				
REVENUES:					
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$(1.46)	$2.47	$2.63	$(9.57)	$0.94
Diluted	$(1.46)	$2.32	$2.51	$(9.57)	$0.93
CASH DIVIDEND DECLARED PER COMMON SHARE	$0.35	$0.3375	$0.30	$0.30	$0.2925
CASH FLOW DATA:					
Cash provided by operating activities	$2,837	$5,903	$5,117	$4,356	$5,357
Cash used in investing activities	$(4,984)	$(5,812)	$(8,503)	$(5,462)	$(9,965)
Cash provided by (used in) financing activities	$2,083	$158	$3,181	$(336)	$6,356
BALANCE SHEET DATA (AT END OF PERIOD)					
Total assets	$41,611	$41,835	$37,179	$29,914	$38,593
Long-term debt, net of current maturities	$12,157	$10,626	$12,640	$12,295	$13,175
Total equity	$17,896	$17,961	$15,264	$12,341	$17,017

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

Financial Data

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

	Years Ended December 31,		
	2012	2011	2010
Net Production:			
Natural gas (bcf)	1,128.8	1,004.1	924.9
Oil (mmbbl)	31.3	17.0	10.9
NGL (mmbbl)	17.6	14.7	7.5
Natural gas equivalent (bcfe)[(a)]	1,422.1	1,194.2	1,035.2
Natural Gas, Oil and NGL Sales ($ in millions):			
Natural gas sales	$2,004	$3,133	$3,169
Natural gas derivatives – realized gains (losses)	328	1,656	1,982
Natural gas derivatives – unrealized gains (losses)	(331)	(669)	425
Total natural gas sales	2,001	4,120	5,576
Oil sales	2,829	1,523	822
Oil derivatives – realized gains (losses)	39	(60)	74
Oil derivatives – unrealized gains (losses)	857	(128)	(1,033)
Total oil sales	3,725	1,335	(137)
NGL sales	526	603	257
NGL derivatives – realized gains (losses)	(9)	(42)	—
NGL derivatives – unrealized gains (losses)	35	8	(49)
Total NGL sales	552	569	208
Total natural gas, oil and NGL sales	$6,278	$6,024	$5,647
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$1.77	$3.12	$3.43
Oil ($ per bbl)	$90.49	$89.80	$75.29
NGL ($ per bbl)	$29.89	$40.96	$34.38
Natural gas equivalent ($ per mcfe)	$3.77	$4.40	$4.10
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$2.07	$4.77	$5.57
Oil ($ per bbl)	$91.74	$86.25	$82.10
NGL ($ per bbl)	$29.37	$38.12	$34.38
Natural gas equivalent ($ per mcfe)	$4.02	$5.70	$6.09
Other Operating Income[(b)] ($ in millions):			
Marketing, gathering and compression net margin	$119	$123	$127
Oilfield services net margin	$142	$119	$32
Other Operating Income[(b)] ($ per mcfe):			
Marketing, gathering and compression net margin	$0.08	$0.10	$0.12
Oilfield services net margin	$0.10	$0.10	$0.03

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	Years Ended December 31,		
	2012	2011	2010
Expenses ($ per mcfe):			
Natural gas, oil and NGL production	$0.92	$0.90	$0.86
Production taxes	$0.13	$0.16	$0.15
General and administrative expenses	$0.38	$0.46	$0.44
Natural gas, oil and NGL depreciation, depletion and amortization	$1.76	$1.37	$1.35
Depreciation and amortization of other assets	$0.21	$0.24	$0.21
Interest expense[c]	$0.06	$0.03	$0.08
Interest Expense ($ in millions):			
Interest expense	$84	$30	$99
Interest rate derivatives – realized (gains) losses	$(1)	$7	$(14)
Interest rate derivatives – unrealized (gains) losses	$(6)	$7	$(66)
Total interest expense	$77	$44	$19

(a) Natural gas 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. Given recent natural gas, oil and NGL prices, the price for an mcfe of natural gas is significantly less than the price for an mcfe of oil or NGL.

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

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

We are the second-largest producer of natural gas, a top 11 producer of liquids and the most active driller of wells in the U.S. We own interests in approximately 45,400 producing natural gas and oil wells that are currently producing approximately 3.9 bcfe per day, net to our interest. The Company has built a large resource base of onshore U.S. unconventional natural gas and liquids assets. Our core natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. In addition, we have built 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 Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas; and the Niobrara Shale in the Powder River Basin in Wyoming. We have also vertically integrated many of our operations and own substantial marketing, compression and oilfield services businesses.

Proved Reserves. The Company's December 31, 2012 estimated proved reserves were 15.690 tcfe, a decrease of 3.099 tcfe, or 17%, from 18.789 tcfe at year-end 2011. The decrease was primarily price related as natural gas prices in 2012 declined to the lowest levels in ten years. The 2012 proved reserve movement included 6.391 tcfe of extensions, downward revisions of 5.414 tcfe resulting from lower natural gas prices and 1.349 tcfe resulting from changes to previous estimates. In 2012, we produced 1.422 tcfe, acquired 42 bcfe and divested 1.347 tcfe of estimated proved reserves, including the disposition of 1.013 tcfe associated with the sale of our Permian Basin assets in September and October 2012.

Downward price revisions of 5.414 tcfe were the result of a decrease in natural gas prices used in estimating proved reserves as of December 31, 2012 by $1.36, or 33%, to $2.76 per mcf from $4.12 per mcf as of December 31, 2011, using the trailing 12-month average prices required by the SEC. The reserve reductions included the loss of significant proved undeveloped reserves, primarily in the Barnett Shale and the Haynesville Shale plays, for which future development is uneconomic at the natural gas prices used in the reserves estimates. As a result of lower estimated reserves as of September 30, 2012, we were required to impair the carrying value of our natural gas and oil properties and, if the trailing 12-month average natural gas, oil and NGL prices are lower in future periods, we could have additional impairments. An impairment of this type is a non-cash charge that does not impact our liquidity or our ability to comply with financial covenants. Future impairments of the carrying value of our natural gas and oil properties, if any, will be dependent on many factors, including natural gas, oil and NGL prices, production rates, levels of reserves, the evaluation of costs excluded from amortization, the timing and impact of asset sales, future development costs and service costs. We refer you to the risk factor “Declines in the prices of natural gas and oil could result in a write-down of our asset carrying values” included in Item 1A of this report and the discussion below of the full cost method of accounting under Application of Critical Accounting Policies – Natural Gas and Oil Properties in this Item 7. In addition, see Natural Gas and Oil Properties in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report. The 1.349 tcfe downward revisions to previous estimates were primarily the result of altering our development plans as we made changes in rig allocations to shift rigs from natural gas to liquids-rich plays and to focus drilling on the core areas of our plays. See Note 10 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Production. Our 2012 production of 1.422 tcfe consisted of 1.129 tcf of natural gas (80% on a natural gas equivalent basis), 31.3 mmbbls of oil (13% on a natural gas equivalent basis) and 17.6 mmbbls of NGL (7% on a natural gas equivalent basis). Daily production for 2012 averaged 3.886 bcfe, an increase of 614 mmcfe, or 19%, over the 3.272 bcfe produced per day in 2011. During 2012, Chesapeake curtailed approximately 70 bcf of net natural gas production, or an average of approximately 190 mmcf per day of natural gas spread across the year. We undertook these curtailments primarily in the first half of 2012 in response to continued low natural gas prices. The curtailed volumes were located primarily in the Haynesville and Barnett shale plays.

In recognition of the value gap between liquids and natural gas prices, Chesapeake directed a significant portion of its technological and leasehold acquisition expertise during the past four years to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and, we believe, more profitable portfolio between natural gas and liquids. In 2012, our production of liquids averaged approximately 133,550 bbls per day, a 54% increase over the 2011 average, as a result of the increased development of our unconventional liquids-rich plays. We expect to increase our liquids production through our drilling activities by approximately 27% in 2013 compared to 2012.

Other Operating Segments. In addition to our exploration and production operating segment, we also have a marketing, gathering and compression operating segment and an oilfield services operating segment that we utilize as a financial and operational hedge against inflation and to help assure that we have access to quality services. In October 2011, we formally segregated our oilfield services businesses under our wholly owned subsidiary, COS, and its wholly owned subsidiary COO. COO's subsidiaries include a leading U.S. drilling contractor, oilfield trucking company, oilfield rental provider and a hydraulic fracturing business. Our oilfield services operating segment is separately capitalized, has its own revolving bank credit facility and COO issued senior notes in 2011. In September 2009, we formally segregated our midstream gathering services under a wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD). During 2012, we sold the majority of our midstream business, including our investment in Access Midstream Partners, L.P. (NYSE:ACMP), as described under Recent Sales - Midstream Sales below. We have retained a minor portion of our midstream gathering business and still own significant marketing and compression operations businesses.

Sales. Our business strategy is to create value for investors by building, developing and now harvesting what we believe is the largest onshore natural gas and liquids-rich resource base in the U.S. After years of building our resource base, we are focused on developing the 10 plays where we have a #1 or #2 ownership position and selling assets (outright or through joint venture transactions) that are non-core or do not fit our long-term plans. During 2012, we completed sales of non-core natural gas and oil properties, our midstream business and preferred equity interests in a subsidiary for proceeds of approximately $11.6 billion. We have announced our intention to sell natural gas and oil properties, midstream and other assets for expected total proceeds of $4 - $7 billion in 2013. Our sales program, together with our forecasted operating cash flow and borrowings under our corporate revolving bank credit facility, are anticipated to fully fund the Company’s 2013 capital expenditure program and further reduce the Company’s long-term debt. We refer you to risks associated with our sales plans, as described in Planned Sales below.

Recent Developments

On January 29, 2013, Aubrey K. McClendon, our President, Chief Executive Officer (CEO) and a director, agreed to retire from the Company. Mr. McClendon will continue to serve as CEO, President and a director until the earlier of April 1, 2013 or the time at which his successor is appointed. Mr. McClendon's departure from the Company will be treated as a termination without cause under his employment agreement.

Also on January 29, 2013, the Compensation Committee of our Board of Directors approved retention awards for 14 of the Company's senior management team in the form of time-vested stock options to purchase an aggregate of 2.56 million shares of common stock. These awards, ranging from 150,000 to 360,000 stock options, have an exercise price equal to the closing price of the Company's common stock on the grant date, and vest one-third on each of the third, fourth and fifth anniversaries of the grant date. The options are subject to accelerated vesting if the executive is terminated (other than for cause) during the vesting period; however, no accelerated vesting will occur if the executive retires or voluntarily resigns prior to vesting.

On February 20, 2013, we announced that our Board of Directors had received the results of its previously announced review of the financing arrangements between Mr. McClendon (and the entities through which he participates in the Founder Well Participation Program (FWPP)) and third parties identified as having a financial relationship with us, as well as other matters. The review, which was led by the Audit Committee of the Board with the assistance of independent counsel retained by the independent members of the Board in April 2012, has been substantially completed. In connection with the review, millions of pages of documents were collected and reviewed and more than 50 interviews of Chesapeake and third-party personnel were conducted.

Among the transactions reviewed were the 2008-2012 financing arrangements between EIG Global Energy Partners (EIG) and affiliates of Mr. McClendon regarding financing of his participation in the FWPP, as well as the preferred stock investments by EIG in CHK Utica, L.L.C. and CHK Cleveland Tonkawa, L.L.C. See Noncontrolling Interests in Note 8 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the preferred stock investment transactions. The review of the financing arrangements did not reveal any improper benefit to Mr. McClendon or increased cost to the Company as a result of the overlap in the financial relationships.

The review also covered:

- other relationships in which both Mr. McClendon and the Company conducted business with the same financial institutions;
- the trading activities of the Heritage Hedge Fund (co-founded by Mr. McClendon) through 2007, when the Heritage Hedge Fund ceased operations; and
- other matters, including issues regarding administration of the FWPP, and a 1998 loan to Mr. McClendon by then Board member Frederick B. Whittemore.

Based on the documents reviewed and interviews conducted, no intentional misconduct by Mr. McClendon or any of the Company's management was found by the Board concerning these relationships and/or these transactions and issues.

We also announced on February 20, 2013 that our Board of Directors had concluded that the Company did not violate antitrust laws in connection with the acquisition of Michigan oil and gas rights in 2010. As described in Item 3 and in Note 4 of the notes to our consolidated financial statements included in Item 8 of this report, in June 2012 we received a subpoena duces tecum from the Antitrust Division, Midwest Field Office, of the United States Department of Justice, and demands for documents and information from state governmental agencies, investigating possible antitrust violations arising from 2010 leasing activities. The Board commenced its own investigation of these allegations in June 2012 and based its conclusion on a thorough review conducted independently by outside counsel and cooperation with the Department of Justice.

On February 25, 2013, we announced we had entered into an agreement whereby Sinopec International Petroleum Exploration and Production Corporation (Sinopec) will purchase a 50% undivided interest in 850,000 of our net oil and natural gas leasehold acres in the Mississippi Lime play in northern Oklahoma (425,000 acres net to Sinopec). The total consideration for the transaction will be $1.02 billion in cash, of which approximately 93% will be received upon closing. Payment of the remaining proceeds will be subject to certain customary title contingencies. Production from these assets (including Mississippi Lime and other formations), net to our interest and prior to Sinopec's purchase, averaged approximately 34 thousand barrels of oil equivalent per day in the 2012 fourth quarter and, as of December 31, 2012, there was approximately 140 million barrels of oil equivalent of net proved reserves associated with the assets. All future exploration and development costs in the joint venture will be shared proportionately between the parties with no drilling carries involved. As the operator of the project, we will conduct all leasing, drilling, completion, operations and marketing for the joint venture. The transaction is anticipated to be completed in the 2013 second quarter.

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Recent Sales

An essential part of our business strategy in 2012 and 2013 is using the proceeds from sales to fund the capital expenditures needed to transition from a natural gas-focused drilling program to a liquids-focused drilling program and to reduce our indebtedness. Below we describe transactions completed in 2012 and the continuing benefits of our joint ventures which were completed prior to 2012.

Permian Basin. In September and October 2012, we sold the vast majority of our Permian Basin assets, representing approximately 6% of our total proved reserves as of June 30, 2012 and 6% of our 2012 second quarter net production, in three separate transactions for total net cash proceeds of approximately $3.091 billion. Approximately $466 million of additional consideration was withheld subject to certain title, environmental and other standard contingencies. Following the closing, we received approximately $84 million of such consideration, including $45 million received subsequent to December 31, 2012, and we expect to receive the majority of the remaining contingent amount in 2013. Of the total proceeds, we allocated approximately $42 million to our Permian Basin midstream and other fixed assets. The remaining proceeds were allocated to our Permian Basin natural gas and oil properties.

In September 2012, to facilitate our Permian Basin divestiture process, we purchased the remaining reserves from our Permian Basin volumetric production payment (VPP #7), originally entered into in June 2010, for $313 million. The reserves purchased totaled 28 bcfe and were subsequently sold to the buyers of our Permian Basin assets described above.

Chitwood Knox. In December 2012, we sold approximately 40,000 net acres of non-core leasehold in the Chitwood Knox play in Oklahoma for approximately $540 million in cash. The properties included approximately 13 mmcfe per day of current net production.

Non-Core Utica Shale. In August 2012, we sold approximately 72,000 net acres of non-core leasehold in the Utica shale play in Ohio to affiliates of EnerVest, Ltd. for approximately $358 million in cash.

Texoma Woodford. In April 2012, we sold approximately 60,000 net acres of leasehold in the Texoma Woodford play in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for approximately $572 million in cash. The properties included approximately 25 mmcfe per day of current net production.

Under full cost accounting rules, we account for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss. In conjunction with certain transactions, affiliates of Mr. McClendon sold interests in the same properties and on the same terms as those that applied to the interests sold by the Company, and proceeds were paid to the sellers based on their respective ownership. These interests were acquired through the FWPP, which provides Mr. McClendon a contractual right to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company’s leasehold through June 2014.

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

In December 2012, our wholly owned midstream subsidiary, CMD, sold its wholly owned subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO), which held a substantial majority of our midstream business, to ACMP for cash proceeds of $2.16 billion, subject to post-closing adjustments. These midstream assets are located primarily in our Marcellus, Utica, Eagle Ford, Haynesville and Niobrara shale plays. The transaction with ACMP included new gathering and processing agreements covering acreage dedication areas in these plays. We recorded a $289 million pre-tax gain associated with this transaction. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of this transaction.

In November 2012, we sold our oil gathering business in the Eagle Ford Shale to Plains Pipeline, L.P. for cash consideration of approximately $115 million. Payment of an additional $10 million was subject to a closing contingency, and we received the additional proceeds subsequent to December 31, 2012. We recorded a $7 million pre-tax loss associated with this transaction in 2012 that will adjust to a $3 million pre-tax gain with the receipt of the $10 million contingency payment in 2013. In connection with the sale, we entered into new gathering and transportation agreements covering acreage dedication areas.

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Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our natural gas and oil assets in our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and existing wells within an area of mutual interest in the Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 new net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold. For further discussion, see Noncontrolling Interests in Note 8 of the notes to our consolidated financial statements included in Item 8 of this report.

Volumetric Production Payment (VPP). In March 2012, we monetized certain of our producing assets in the Anadarko Basin Granite Wash through a ten-year VPP for proceeds of approximately $744 million. The transaction included approximately 160 bcfe of proved reserves and approximately 125 mmcfe per day of net production at the time of the transaction. Chesapeake has retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores and we also retain all production beyond the specified volumes sold in the transaction. This transaction was our tenth VPP. The cash proceeds from this transaction were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Other VPPs we completed in 2007 – 2011 are detailed in Note 11 of the notes to our consolidated financial statements included in Item 8 of this report.

Joint Ventures. As of December 31, 2012, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments for future drilling and completion cost carries of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. The carry obligations paid by a joint venture partner are for a specified percentage of our drilling and completion cost obligations. In addition, a joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner. We bill our joint venture partners for their drilling carry obligations at the same time we bill them and other joint working interest owners for their share of drilling costs as they are incurred. The transactions are detailed below.

Primary Play	Joint Venture Partner[(a)]	Joint Venture Date	Interest Sold	Cash Proceeds Received at Closing	Total Drilling Carries		Total Cash and Drilling Carry Proceeds	Drilling Carries Remaining[(b)]
				($ in millions)				
Utica	TOT	December 2011	25.0%	$610	$1,422	(c)	$2,032	$1,153
Niobrara	CNOOC	February 2011	33.3%	570	697	(d)	1,267	463
Eagle Ford	CNOOC	November 2010	33.3%	1,120	1,080		2,200	—
Barnett	TOT	January 2010	25.0%	800	1,404	(e)	2,204	—
Marcellus	STO	November 2008	32.5%	1,250	2,125		3,375	—
Fayetteville	BP	September 2008	25.0%	1,100	800		1,900	—
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508	(f)	3,158	—
				$7,100	$9,036		$16,136	$1,616

(a) Joint venture partners include Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Plains Exploration & Production Company (PXP).

(b) As of December 31, 2012.

(c) The Utica drilling carries cover 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. We expect to fully utilize these drilling carry commitments prior to expiration. See Drilling Commitments in Note 4 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the Utica drilling carries.

(d) The Niobrara drilling carries cover 67% of our drilling and completion costs for Niobrara wells drilled and must be used by December 2014. We expect to fully utilize these drilling carry commitments prior to expiration.

(e) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of drilling carry obligation billed and $425 million for the remaining drilling carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs. In May 2012, Chesapeake and TOT agreed to further reduce the minimum rig count from six to two rigs.

(f) In September 2009, PXP accelerated the payment of its remaining drilling carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

The drilling and completion carries in our joint venture agreements allow us to reduce our finding costs. During 2012 and 2011, our drilling and completion costs included the benefit of approximately $784 million and $2.570 billion, respectively, of drilling and completion carries paid by our joint venture partners. Our drilling and completion costs in 2013 and 2014 will continue to be partially offset by the use of drilling and completion carries associated with our joint venture agreements. Once the remaining carries have been used, we anticipate our net drilling and completion costs will increase in the respective plays.

During 2012, we sold interests in additional leasehold we acquired in the Marcellus, Barnett and Utica shale plays to our joint venture partners TOT and STO for approximately $272 million pursuant to our joint venture agreements. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Planned Sales

We anticipate completing the sale of nearly all of our remaining midstream business, including our Mid-Continent gathering systems and other assets, in the 2013 first half.

In addition to the Mississippi Lime joint venture discussed under Recent Developments, we have other natural gas and oil assets currently for sale, including our northern Eagle Ford assets and various portions of our Marcellus and Utica leasehold in Pennsylvania and Ohio that we consider non-core.

We do not have binding agreements for all of our planned asset sales and our ability to consummate each of these transactions is subject to changes in market conditions and other factors beyond our control.

Liquidity and Capital Resources

Liquidity Overview

Our business is capital intensive. Historically, we have made capital expenditures that exceeded our cash flow from operations. We project that our capital expenditures will continue to exceed our operating cash flow in 2013, although by a significantly smaller amount as we continue our transition to an asset base more balanced between natural gas and oil from one primarily focused on natural gas and we shift to harvesting assets after approximately a decade of asset accumulation. We also expect to benefit from operating efficiencies associated with our strategy of developing the core of the core of our substantial leasehold position. During 2012, the combination of high capital expenditures and reduced cash flow as a result of low natural gas prices led to a spending “gap” that we filled with borrowings and proceeds from sales of assets that we determined were non-core or did not fit our long-term plans. We increased our debt, net of unrestricted cash, by approximately $2.058 billion, to $12.333 billion, in 2012.

As of December 31, 2012, we had approximately $4.338 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving bank credit facilities) compared to $3.134 billion as of December 31, 2011. As of December 31, 2012, we had negative working capital of approximately $3.318 billion compared to negative working capital of approximately $3.905 billion as of December 31, 2011. Working capital deficits have existed largely because our capital spending generally has exceeded our cash flow from operations.

For 2013, we plan to fund capital expenditures with operating cash flow, borrowings under our revolving bank credit facilities and proceeds from asset sales. Our 2013 capital expenditure budget is approximately 50% less than our 2012 capital expenditures, and as operator of a substantial portion of our natural gas and oil properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to expeditiously reduce at least a portion of our capital spending if needed. To mitigate our downside exposure to lower commodity prices, we have hedged approximately 72% of our forecasted 2013 natural gas, oil and NGL production revenue, including downside hedge protection on approximately 50% of our 2013 estimated natural gas production at an average price of $3.62 per mcf (most of these hedges were established subsequent to December 31, 2012) and 85% of our 2013 estimated oil production at an average price of $95.45 per bbl. Hedging allows us to reduce the effect of price volatility on our cash flows and earnings before interest, taxes, depreciation, depletion and amortization (EBITDA). Based on our forecasted operating cash flow for 2013, which takes into account our current hedges, and considering our 2013 forecasted capital expenditures, we are expecting a funding gap of approximately $4 billion. We believe we will have ample liquidity to fill the funding gap with borrowing capacity under our corporate revolving bank credit facility. However, we plan to offset the need to borrow under our corporate revolving bank credit facility with sales of certain of our natural gas and oil properties, midstream and other assets and expect those total proceeds to be $4 - $7 billion in 2013. Through February 2013, we have closed or have binding agreements on approximately $1.4 billion of asset sales. Asset sales are uncertain and subject to changes in market conditions and other factors beyond our control. Any remaining cash available after applying these proceeds to the deficit between capital expenditures and operating cash flow will be available to reduce our long-term debt.

As part of our sales planning and capital expenditure budgeting process, we closely monitor the resulting effects on 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 corporate revolving bank credit facility. While asset sales enhance our ability to reduce debt, sales of producing natural gas and oil properties may adversely affect the amount of cash flow and EBITDA we generate and reduce the amount and value of collateral available to secure our obligations, both of which can be exacerbated by low prices for our production. In September 2012, we obtained an amendment to our revolving bank credit facility agreement that relaxed the required indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. See Bank Credit Facilities - Corporate Credit Facility below for discussion of the terms of the amendment. We would have been unable to meet the required ratio as of September 30, 2012 without this amendment primarily because the closing of certain asset sales transactions occurred in the fourth quarter and not in September as we had anticipated. As a result, without the amendment, we would have been unable to reduce our indebtedness sufficiently as of September 30, 2012 to maintain our covenant compliance. As of December 31, 2012, we were in compliance with the current covenants and would have also been in compliance with the more restrictive covenants that existed prior to the amendment. Failure to maintain compliance with the covenants of our revolving bank credit facility agreement could result in the acceleration of outstanding indebtedness under the facility and lead to cross defaults under our senior note and contingent convertible senior note indentures, hedge facility, equipment master lease agreements and term loan.

We expect to have adequate liquidity to repay $464 million of senior note indebtedness that matures in 2013. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to various arrangements, agreements and investments described in Contractual Obligations and Off-Balance Sheet Arrangements below and in Note 4 of the notes to our consolidated financial statements included in Item 8 of this report, recognizing that we may be required to meet such commitments even if our business plan assumptions were to change due to circumstances beyond our control.

Based upon our capital expenditure budget, expected commodity prices (including the prices for our currently hedged production), our forecasted drilling and production, projected levels of indebtedness and binding purchase and sale agreements for certain future asset sales, we are projecting that we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility, and we will have adequate liquidity, through 2013. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures and other spending, to adapt to potential negative developments if needed.

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Sources of Funds

The following table presents the sources of our cash and cash equivalents for 2012, 2011 and 2010. See Recent Sales above and Notes 8, 11 and 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the sales of natural gas and oil assets, sales of other assets and sales of preferred interests and noncontrolling interests in subsidiaries.

	2012	2011	2010
	($ in millions)		
Cash provided by operating activities[a]	$2,837	$5,903	$5,117
Sales of natural gas and oil assets:			
Permian Basin	3,130	—	—
Texoma	572	—	—
Chitwood Knox	540	—	—
Fayetteville Shale	—	4,270	—
TOT (Utica) joint venture	—	610	—
CNOOC (Niobrara) joint venture	—	553	—
CNOOC (Eagle Ford) joint venture	—	—	1,085
TOT (Barnett) joint venture[b]	—	425	853
Joint venture leasehold	272	511	440
Volumetric production payments	744	849	1,622
Other natural gas and oil properties	626	433	292
Total sales of natural gas, oil and other assets	5,884	7,651	4,292
Sales of other assets:			
Sale of CMO	2,160	—	—
Sale of AMS	—	879	—
Sale of Springridge gathering system	—	—	500
Proceeds from sales of other assets	332	433	383
Total proceeds from sales of other assets	2,492	1,312	883
Other sources of cash and cash equivalents:			
Sale of investment in ACMP	2,000	—	—
Sale of preferred interest and ORRI in CHK C-T	1,250	—	—
Sale of preferred interest and ORRI in CHK Utica	—	1,250	—
Sale of noncontrolling interest in Chesapeake Granite Wash Trust	—	410	—
Proceeds from investments	—	101	—
Proceeds from long-term debt	6,985	1,614	1,967
Proceeds from credit facility borrowings, net	—	—	1,814
Proceeds from issuance of preferred stock	—	—	2,562
Cash received from financing derivatives[c]	—	1,043	621
Other	84	341	20
Total other sources of cash and cash equivalents	10,319	4,759	6,984
Total sources of cash and cash equivalents	$21,532	$19,625	$17,276

(a) Includes cash settlements of derivative instruments classified as operating cash flows. Also includes cash distributions of $56 million, $85 million and $88 million in 2012, 2011 and 2010, respectively, from ACMP and its predecessor, and $28 million and $58 million in 2011 and 2010, respectively, from our equity investee, FTS International, Inc. and its predecessor.

(b) 2011 includes the $425 million acceleration of the payment of TOT's remaining drilling carry in exchange for a reduction in the obligation. See Note 11 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

(c)

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

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Cash flow from operations is a source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $2.837 billion in 2012 compared to $5.903 billion in 2011 and $5.117 billion in 2010. The decline in cash flow from operations from 2011 to 2012 is primarily the result of a decrease in the realized natural gas price (excluding the effect of unrealized gains or losses on derivatives) from $4.77 per mcf in 2011 to $2.07 per mcf in 2012. The increase in cash flow from operations from 2010 to 2011 is primarily the result of an increase in production of 159 bcfe. 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 natural gas and oil properties and 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 corporate securities in 2012, 2011 and 2010. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

	2012		2011		2010	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
	($ in millions)					
Senior notes	$1,300	$1,263	$1,650	$1,614	$2,000	$1,967
Term loans[(a)]	6,000	5,722	—	—	—	—
Convertible preferred stock	—	—	—	—	2,600	2,562
Total	$7,300	$6,985	$1,650	$1,614	$4,600	$4,529

(a) Includes principal amounts of $4.0 billion and $2.0 billion for our May 2012 term loans and November 2012 term loan, respectively. The entire principal amount of the May 2012 term loans was repaid in October and November 2012 without penalty.

Our $4.0 billion corporate revolving bank credit facility, our $500 million oilfield services revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use these revolving bank credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $20.318 billion and repaid $21.650 billion in 2012, borrowed $15.509 billion and repaid $17.466 billion in 2011 and borrowed $15.117 billion and repaid $13.303 billion in 2010 under our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves are currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. We believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our oilfield services facility is secured by substantially all of our wholly owned oilfield services assets and is not subject to periodic borrowing base redeterminations. From September 2009 until June 2012, we also had a $600 million midstream revolving bank credit facility which we terminated in June 2012. Our revolving bank credit facilities are described below under Bank Credit Facilities.

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Uses of Funds

The following table presents the uses of our cash and cash equivalents for 2012, 2011 and 2010:

	2012	2011	2010
	($ in millions)		
Natural gas and oil expenditures:			
Drilling and completion costs[(a)]	$(8,707)	$(7,257)	$(5,061)
Acquisitions of proved properties	(342)	(48)	(243)
Acquisitions of unproved properties	(2,043)	(4,296)	(6,015)
Geological and geophysical costs[(b)]	(193)	(210)	(181)
Interest capitalized on unproved properties	(806)	(630)	(687)
Total natural gas and oil expenditures	(12,091)	(12,441)	(12,187)
Other uses of cash and cash equivalents:			
Additions to other property and equipment	(2,651)	(2,009)	(1,326)
Acquisition of drilling company	—	(339)	—
Payments of credit facility borrowings, net	(1,332)	(1,957)	—
Cash paid to purchase debt	(4,000)	(2,015)	(3,434)
Dividends paid	(398)	(379)	(281)
Distributions to noncontrolling interest owners	(218)	(9)	—
Cash paid for financing derivatives[(c)]	(37)	—	—
Additions to investments	(395)	—	(134)
Other	(474)	(227)	(119)
Total uses of cash and cash equivalents	$(21,596)	$(19,376)	$(17,481)

(a) Net of $784 million, $2.570 billion and $1.151 billion in drilling and completion carries received from our joint venture partners during 2012, 2011 and 2010, respectively.

(b) Includes related capitalized interest.

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

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. Drilling and completion costs during 2012 reflected the impact of our deliberate transition to liquids-focused drilling and reduced natural gas drilling and a reduction in the amount of drilling and completion carries received from our joint venture partners. During the 2012 first quarter, our rig count was as high as 165 rigs as we were quickly ramping up our liquids-focused drilling while, at the same time, we were gradually ramping down drilling of natural gas wells. As of February 28, 2013, our rig count had been reduced to 83 operated rigs. Our natural gas drilling activities were sharply reduced in 2012, from 50 rigs at the beginning of the year to an average of 9 rigs in the fourth quarter. The 2012 drilling and completion expenditures also reflected significant well completion costs for natural gas wells that had been drilled, but not completed, in prior periods. These completions, which represented more than 60% of all natural gas wells we completed during 2012, enabled us to hold by production the related leasehold according to the terms of our leases. Approximately 75% of our unproved property leasehold acquisition costs of $2.043 billion during 2012 were focused on adding to our acreage in the Utica, Marcellus and Mid-Continent plays. Capital expenditures related to our midstream, oilfield services and other fixed assets of $2.651 billion during 2012 were primarily related to the expansion of our gathering systems and the growth of our oilfield services businesses, in particular the hydraulic fracturing line of business. We sold substantially all of our midstream business in December 2012.

In October and November 2012, we fully repaid the $4.0 billion May 2012 term loans for $4.0 billion with cash proceeds from asset sales and proceeds from the issuance of our November 2012 term loan. We recorded a loss of approximately $200 million with this repayment.

In 2011, we completed and settled tender offers to purchase $2.044 billion in principal amount of our senior notes and contingent convertible senior notes for $2.186 billion in cash, including approximately $171 million in cash premiums, primarily funded with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets.

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In 2010, we completed and settled tender offers to purchase $3.434 billion in principal amount of our senior notes for $3.434 billion in cash.
We paid dividends on our common stock of $227 million, $207 million and $189 million in 2012, 2011 and 2010, respectively. We paid dividends on our preferred stock of $171 million, $172 million and $92 million in 2012, 2011 and 2010, respectively. The increase in 2011 was due to the issuance of 2.6 million shares of preferred stock in 2010.
During 2012, we had net additions to investments of $395 million, including $109 million of additional investment in FTS International, Inc., $50 million of additional investment in Clean Energy Fuels Corp., $80 million of additional investment in Sundrop Fuels, Inc. and $220 million for three midstream investments that were sold in December 2012 as part of the sale of substantially all of our midstream business to ACMP. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of these investments.

Bank Credit Facilities

During 2012, we used three revolving bank credit facilities as sources of liquidity. In June 2012, we paid off and terminated our midstream credit facility. Our two remaining revolving bank credit facilities are described below.

	Corporate Credit Facility[a]	Oilfield Services Credit Facility[b]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of December 31, 2012	$—	$418
Letters of credit outstanding as of December 31, 2012	$31	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.
(b) Borrower is Chesapeake Oilfield Operating, L.L.C.

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.
Corporate Credit Facility. Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by proved reserves and bear interest at a variable rate. We were in compliance with all covenants under the amended agreement as of December 31, 2012. For further discussion on the terms of our corporate credit facility, see Note 3 of the notes to our consolidated financial statements included in Item 8 of this report.
As described above in Liquidity Overview, in September 2012, we entered into an amendment to the credit facility agreement, effective September 30, 2012. The amendment, among other things, adjusts our required indebtedness to EBITDA ratio covenant through the earlier of (a) December 31, 2013 and (b) the date on which we elect to reinstate the indebtedness to EBITDA ratio in effect prior to the amendment (in either case, the "Amendment Effective Period"). The amendment increased the maximum indebtedness to EBITDA ratio as of September 30, 2012 from 4.00 to 1.00 to 6.00 to 1.00 and revised the required ratio for the next four quarters as shown below. The ratio returns to 4.00 to 1.00 as of December 31, 2013 and thereafter.

Effective Date	Indebtedness to EBITDA Ratio
December 31, 2012	5.00 to 1.00
March 31, 2013	4.75 to 1.00
June 30, 2013	4.50 to 1.00
September 30, 2013	4.25 to 1.00

Our actual indebtedness to EBITDA ratio as of December 31, 2012 was approximately 3.91 to 1.00. The ratio compares consolidated indebtedness to consolidated EBITDA, both non-GAAP financial measures that are defined in the credit facility agreement, for the 12-month period ending on the measurement date. Consolidated indebtedness consists of outstanding indebtedness, less the cash and cash equivalents of Chesapeake and certain of our subsidiaries. Consolidated EBITDA consists of the net income of Chesapeake and certain of our subsidiaries, excluding income from investments and non-cash income plus interest expense, taxes, depreciation, amortization expense and other non-cash expenses, and is calculated on a pro forma basis to give effect to any acquisitions, divestitures or other changes.

The credit facility amendment increases the applicable margin by 0.25% for borrowings under the corporate credit facility on each day during the Amendment Effective Period when borrowings exceed 50% of the borrowing capacity and requires us to pay a fee to each lender in an amount equal to 0.05% of its revolving commitment if the Amendment Effective Period is in effect on June 30, 2013. Based on current commitment levels, this would result in an additional payment of $2 million. In addition, the amendment does not allow our collateral value securing the borrowings to be more than $75 million below the collateral value that was in effect as of September 30, 2012 during the Amendment Effective Period.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. The facility may be expanded from $500 million to $900 million at COO’s option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, but they are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes, term loan and corporate revolving bank credit facility), and bear interest at a variable interest rate. For further discussion of the terms of our oilfield services credit facility, see Note 3 of the notes to our consolidated financial statements included in Item 8 of this report.

Midstream Credit Facility. Prior to June 15, 2012, we utilized a $600 million midstream syndicated senior secured revolving bank credit facility to fund capital expenditures to build natural gas gathering and other systems in support of our drilling program and for general corporate purposes associated with our midstream operations. With the anticipated sale of the substantial majority of our midstream business in the second half of 2012, on June 15, 2012, we paid off and terminated our midstream credit facility.

Hedging Facility

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 6.4 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.4 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. For further discussion of the terms of our hedging facility, see Note 9 of the notes to our consolidated financial statements included in Item 8 of this report.

Term Loans

May 2012 Term Loans. In May 2012, we entered into $4.0 billion of unsecured term loans under a credit agreement that provided for term loans in an aggregate principal amount of $4.0 billion. The net proceeds of the term loans of approximately $3.789 billion after discount, customary fees and syndication costs were used to repay borrowings under our corporate revolving credit facility and for general corporate purposes. The term loans were issued at a discount of 3%, or $120 million, and the customary fees and syndication costs incurred were approximately $91 million. In October and November 2012, we used proceeds from asset sales and our new term loan (the November 2012 term loan described below) to fully repay the May 2012 term loans. We recorded $200 million of associated losses with the repayment, including $86 million of deferred charges and $114 million of debt discount.

November 2012 Term Loan. In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion (November 2012 term loan). Our obligations under the facility rank equally with our outstanding senior notes and contingent convertible senior notes and are unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the new facility, which priced at 98% of par, bear interest at LIBOR plus 4.5%. The LIBOR rate is subject to a floor of 1.25% per annum. The new facility is non-callable in the first year but may be voluntarily repaid without penalty in the second and third years at par plus a specified call premium and may be voluntarily repaid at any time thereafter at par. We used the net proceeds of the new term loan to fully repay the remaining outstanding borrowings under our May 2012 term loans

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and to repay outstanding borrowings under the Company's corporate revolving bank credit facility. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities and the November 2012 term loan discussed above, our long-term debt consisted of the following as of December 31, 2012:

	December 31, 2012 ($ in millions)
7.625% senior notes due 2013[a]	$464
9.5% senior notes due 2015	1,265
6.25% euro-denominated senior notes due 2017[b]	454
6.5% senior notes due 2017	660
6.875% senior notes due 2018	474
7.25% senior notes due 2018	669
6.625% senior notes due 2019[c]	650
6.775% senior notes due 2019	1,300
6.625% senior notes due 2020	1,300
6.875% senior notes due 2020	500
6.125% senior notes due 2021	1,000
2.75% contingent convertible senior notes due 2035[d]	396
2.5% contingent convertible senior notes due 2037[d]	1,168
2.25% contingent convertible senior notes due 2038[d]	347
Discount on senior notes[e]	(425)
Interest rate derivatives[f]	20
Total senior notes, net	10,242
Less current maturities of long-term debt[a]	(463)
Total long-term senior notes, net	$9,779

(a) These senior notes are due July 2013. There is $1 million of discount associated with these notes.

(b) The principal amount shown is based on the exchange rate of $1.3193 to €1.00 as of December 31, 2012. See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for information on our related foreign currency derivatives.

(c) Issuers are COO, an indirect wholly owned subsidiary of the Company, and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. COF is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(d) 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 maturi