NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 24, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

or

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .

Commission file number: 1-12534

Newfield Exploration Company
(Exact name of registrant as specified in its charter)

Delaware (State of incorporation)	72-1133047 (I.R.S. Employer Identification No.)
4 Waterway Square Place, Suite 100, The Woodlands, Texas (Address of principal executive offices)	77380 (Zip Code)

Registrant's telephone number, including area code:
(281) 210-5100

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 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No þ

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 þ 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) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of the 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. ¨

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. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $5.9 billion as of June 30, 2014 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 20, 2015, there were 137,387,180 shares of the registrant's common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Portions of the Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 15, 2015, which is incorporated by reference to the extent specified in Part III of this Form 10-K.

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If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption “Commonly Used Oil and Gas Terms” at the end of Items 1 and 2 of this report. Unless the context otherwise requires, all references in this report to “Newfield,” “we,” “us,” “our” or the “Company” are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest.

Forward-Looking Information

This report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). All statements, other than statements of historical facts included in this report, are forward-looking, including information relating to anticipated future events or results, such as planned capital expenditures, the availability and sources of capital resources to fund capital expenditures and other plans and objectives for future operations. Forward-looking statements are typically identified by use of terms such as “may,” “believe,” “expect,” “anticipate,” “intend,” “estimate,” “proje “target,” “goal,” “plan,” “should,” “will,” “predict,” “potential” and similar expressions that convey the uncertainty of future ev or outcomes. Although we believe that the expectations reflected in such forward-looking statements are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including:

- oil, natural gas and natural gas liquids (NGL) prices;
- the availability and volatility of the securities, capital or credit markets and the cost of capital to fund our operations and business strategies;
- accuracy and fluctuations in our reserves estimates due to sustained low commodity prices;
- ability to develop existing reserves or acquire new reserves;
- the timing and our success in discovering, producing and estimating reserves;
- sustained decline in commodity prices could result in writedowns of assets;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations, including those related to hydraulic fracturing, climate change and over-the-counter derivatives;
- land, legal, regulatory, and ownership complexities inherent in the U.S. oil and gas industry;
- the impact of regulatory approvals;
- the availability and volatility of the securities, capital or credit markets and the cost of capital to fund our operations and business strategies;
- the ability and willingness of current or potential lenders, derivative contract counterparties, customers and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us;
- the prices and quantities of commodities reflected in our commodity derivative arrangements as compared to the actual prices or quantities of commodities we produce or use;
- the volatility and liquidity in the commodity futures and commodity and financial derivatives markets;
- drilling risks and results;
- the prices and availability of goods and services;
- the cost and availability of drilling rigs and other support services;
- global events that may impact our domestic and international operating contracts, markets and prices;

•labor conditions;
•weather conditions;
•environmental liabilities that are not covered by an effective indemnity or insurance;
•competitive conditions;
•terrorism or civil or political unrest in a region or country;
•our ability to monetize non-strategic assets, pay debt and the impact of changes in our investment ratings;
•electronic, cyber or physical security breaches;
•changes in tax rates;
•inflation rates;
•financial counterparty risk;
•the effect of worldwide energy conservation measures;
•the price and availability of, and demand for, competing energy sources;
•the availability (or lack thereof) of acquisition, disposition or combination opportunities; and
•the other factors affecting our business described below under the caption "Risk Factors."

Should one or more of the risks described above occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. See Items 1 and 2, "Business and Properties," Item 1A, "Risk Factors," Item 3, "Legal Proceedings," Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" for additional information about factors that may affect our businesses and operating results. These factors are not necessarily all of the important factors that could affect us. Use caution and common sense when considering these forward-looking statements. Unless securities laws require us to do so, we do not undertake any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

PART I

Items 1 and 2. Business and Properties

General

Newfield Exploration Company is an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. We are a Delaware corporation, incorporated in 1988, that has been publicly traded on the New York Stock Exchange (NYSE) since 1993. We have a unique history of growth, evolving from an offshore, Gulf of Mexico natural gas producer to an onshore, domestic producer focused on liquids-rich resource plays and included in the S&P 500.

Our principal areas of operation are oil and liquids-rich resource plays in the Mid-Continent, Rocky Mountains and onshore Gulf Coast regions of the United States. In addition, we have offshore oil developments in China.

Executive Summary

- Domestic production increased 19% over 2013 to 47.9[(1)] MMBOE. Domestic liquids production grew 38% year-over-year. Consolidated fourth quarter production was 138[(2)] MBOEPD (60% liquids);

- Thirteen year reserve life index (based on 2014 production);

- Approximately 96% of Newfield's 645 MMBOE of proved reserves (47% oil, 12% NGLs and 41% natural gas) are located onshore U.S. Domestic liquids reserves increased 17% year-over-year and represent 57% of domestic proved reserves;

- Proved reserves grew 14% year-over-year (adjusted for 2014 asset sales of 49 MMBOE). Total company and domestic PV-10[(3)] increased 9% and 16%, respectively, over the prior year-end to \$8.8 billion and \$7.7 billion, respectively. Approximately 52% of reserves are proved developed;

- The Anadarko Basin is now the Company's largest producing region, averaging 54,000 BOEPD in the fourth quarter of 2014. The Anadarko Basin comprises 28% of total proved reserves. Acreage in the basin increased to nearly 300,000 net acres;

- Demonstrated continued operational efficiencies, drilling "best in class" wells in each of our four primary focus areas. Average domestic lease operating expenses, on a per barrel basis, decreased 7% over 2013;

- Sold \$1.5 billion in non-strategic assets and used proceeds to redeem our \$600 million 7 % Senior Subordinated Notes due 2018; and

- Commenced production from the Pearl oil development, located offshore China.

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(1) Includes 8.5 Bcf of natural gas produced and consumed in operations.

(2) Includes 2.1 Bcf (3.8 MBOEPD) of natural gas produced and consumed in operations.

(3) PV-10 (as defined) is considered a non-GAAP financial measure by the SEC. See non-GAAP reconciliation in "Reserves – Reserves Sensitivities" below.

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2015 Outlook

Until the last six months, crude oil prices have been reasonably stable, with NYMEX WTI averaging approximately $95 per barrel over the past four years. During this time period, relatively easy access to low-cost capital and advances in horizontal drilling and fracture stimulations led to significant growth in U.S. oil supply. Production in the U.S. in October 2014 surpassed 9 million barrels a day, a level not seen since the mid-1980s. As a result of increased U.S. production as well as other global supply and demand factors, crude oil prices declined by nearly 50% during the fourth quarter of 2014 and continuing into the first quarter of 2015. As of February 20, 2015, NYMEX WTI was approximately $50 per barrel and the three-year forward curve for NYMEX WTI was $61.37 per barrel. In light of the foregoing, projected capital spending and drilling programs by exploration and production companies are expected to dramatically decline.

Given the uncertainty regarding the timing and magnitude of an eventual recovery of crude oil prices, we have reduced planned capital spending in 2015 by approximately 40% compared to 2014 levels, to $1.2 billion (excluding approximately $120 million of expected capitalized interest and direct internal costs). At this investment level, capital expenditures and cash flows for 2015 are expected to be relatively balanced.

Our primary goals during the next 12 months include:

- preserving liquidity and financial strength;
- limiting new borrowings and balancing capital investments with cash flows;
- high-grading investments based on rates of return;
- implementing a plan to reduce gross general and administrative expenses by 10% to 15%; and
- implementing a plan to reduce domestic per unit lease operating costs by approximately 5% to 15%.

Our 2015 domestic production, at the mid-point, is expected to be about 48.5 MMBOE, up 8% when adjusted for asset sales during 2014. Including oil production from our recent Pearl development, offshore China, our total company production is expected to increase 18% year-over-year.
Our estimated 2015 capital expenditure budget and estimated production for our strategic plays are shown below:

We are planning to reduce our activity levels in lower-return “held-by-production” areas across our portfolio, allowing for increased investment in the higher-return Anadarko Basin of Oklahoma. Approximately 70% of our planned capital investments in 2015 will be allocated to the Anadarko Basin, which is characterized by resilient economics at lower prices and a deep inventory of drilling opportunities in the SCOOP, STACK and Springer plays. We expect the ongoing reduction of service costs to further enhance returns in these plays. As such, we have elected to significantly slow down our investments in the Uinta Basin, Williston Basin and Eagle Ford plays.

We currently expect to fund 2015 investments through cash flows from operations (inclusive of realized derivative contract gains and losses) and borrowings under our credit facility, as needed. At year-end 2014, more than 85% of our expected 2015 domestic crude oil production was subject to derivative instruments intended to manage the variability associated with future changes in commodity prices. For a complete discussion of our derivative activities, a list of open contracts as of December 31, 2014 and the estimated fair value of those contracts as of that date, see Note 5, “Derivative Financial Instruments,” to our consolidated financial statements in Item 8 of this report.

Our Business Strategy

Despite a reduced capital budget in 2015 that is reflective of the current price environment, our primary, long-term goal continues to be delivering stockholder value through consistent growth of cash flow, production and reserves. Over the past several years, we have refined our asset base and focused our investments on oil and liquids-rich resource plays in the United States. Today, we operate in several U.S. basins with our primary growth area located in the Anadarko Basin. The Anadarko Basin has an extensive inventory of attractive opportunities capable of sustainable growth. Key components of our business strategy include:

Focusing on organic opportunities through disciplined capital investments. While we consider various growth opportunities, including strategic acquisitions, our primary focus is organic growth. Our capital program is designed to allocate investments based on projects that maximize our production and reserve growth at attractive returns.

Continuously improving operations and returns. Controlling the costs to find, develop and produce oil, natural gas and NGLs is critical to creating long-term stockholder value. Our focus areas are characterized by large, contiguous acreage positions and multiple, stacked geologic horizons. As the operator of a majority of our leaseholds, we believe we can consistently increase production and reserves while improving operational efficiencies. For example, in 2014, we reduced our drilling days to total depth by as much as 11% in SCOOP and 24% in STACK, our largest capital investment areas.

Preserving a strong and flexible capital structure. Maintaining a strong capital structure that protects our balance sheet and liquidity is central to our business strategy. For 2015, our goal will be to continue to preserve financial flexibility through strong credit metrics and ample liquidity as we seek to manage the inherent commodity price and operational risks in our industry. As we have done historically, we may adjust our capital program throughout the year, divest non-strategic assets and use derivatives to protect a portion of our future production from commodity price volatility to ensure adequate funds to execute our drilling programs. For example, in 2014, we sold our Granite Wash and other non-strategic assets for approximately $600 million and used the proceeds to redeem our $600 million 7 % Senior Subordinated Notes due 2018.

Maintaining a diverse asset base with ongoing portfolio management. Beginning in 2009, we transitioned from a conventional, natural gas-focused company to an unconventional company focused on oil and liquids-rich resource plays in the United States. By maintaining an asset portfolio focused on several key U.S. basins, we increase our flexibility to respond to, and limit our exposure to, the volatility and unique risks our industry faces, such as geologic risks, geographic risks and regional price risks. In line with this element of our strategy and the current weakness in commodity prices, approximately 70% of our 2015 capital investments will be focused on the high-return SCOOP and STACK plays of the Anadarko Basin in Oklahoma.

Executing select, strategic acquisitions and divestitures. We target complementary acquisitions in existing core areas and focus on acquisition opportunities where our operating and technical knowledge is transferable and drilling results can be forecasted with confidence. In addition, from 2012 through 2014, we divested over $2.1 billion in non-strategic assets, supplementing our cash flow and allowing our teams to focus on our core resource plays.

Attracting and retaining quality employees who are aligned with stockholders' interests. We believe in hiring top-tier talent and are committed to our employees' career development. We believe that employees should be rewarded for their performance and that their interests should be aligned with those of our stockholders. As a result, we reward and encourage our employees through performance-based annual compensation and long-term equity-based incentives.

Description of Properties

We have strategically focused on onshore resource plays in the United States. Our domestic plays represent approximately 96% of our proved reserves at year-end 2014. The remaining 4% of our proved reserves are attributable to our offshore developments in China.

Mid-Continent. Approximately 46% of our proved reserves are located in our Mid-Continent region. Our assets are comprised of more than 400,000 net acres in the Anadarko and Arkoma basins where we have over a decade of experience developing the Woodford Shale.

Anadarko Basin. We have about 300,000 net acres in the Anadarko Basin. As of December 31, 2014, we had drilled approximately 138 wells in the Anadarko Basin, with wells yielding high volumes of oil and natural gas liquids. Our average net production in the fourth quarter of 2014 was approximately 54,000 BOEPD (27% oil and 34% NGLs), an increase of 118% compared to the fourth quarter of 2013.

Arkoma Basin. We have significant dry gas production from the Arkoma Basin. The area represents approximately 18% of our total consolidated proved reserves. Our investment levels in this area have been significantly curtailed due to low natural gas prices over the past several years. As of December 31, 2014, we had approximately 146,000 net acres in the Arkoma Basin and our net production for the fourth quarter of 2014 was approximately 18,000 BOEPD (99% dry gas). Substantially all of our acreage in this region is held by production.

Rocky Mountains. Approximately 43% of our proved reserves at year end 2014 are located in the Rocky Mountains region. We are assessing and developing our Rocky Mountains region, which is comprised of more than 250,000 net acres in the Williston Basin of North Dakota and Montana as well as the Uinta Basin of Utah. Our assets are primarily oil and are characterized by long-lived production.

Williston Basin. We have approximately 92,000 net acres in the Williston Basin, of which approximately 40,000 acres are being developed in the Bakken and Three Forks plays of North Dakota. Our activities are currently focused on development and we are drilling multi-well pads with lateral lengths as long as 10,000 feet. Fourth quarter 2014 net production averaged approximately 20,000 BOEPD (74% oil and 10% NGLs), representing an increase of 47% compared to the fourth quarter of 2013.

Uinta Basin. We have approximately 225,000 net acres in the Uinta Basin, and our operations can be divided into two areas: the Greater Monument Butte Unit (GMBU) waterflood and an area to the north and adjacent to the GMBU that we refer to as the Central Basin.

Our net production from the Uinta Basin during the fourth quarter of 2014 averaged approximately 25,000 BOEPD (78% oil and 3% NGLs). As of December 31, 2014, we have drilled a combination of 83 vertical and horizontal wells in the Central Basin to hold our acreage. Overall production in the Uinta Basin grew 11% in the fourth quarter of 2014 compared to the fourth quarter of 2013.

Onshore Gulf Coast. About 7% of our proved reserves are located in the onshore Gulf Coast region. We have approximately 25,000 net acres currently in development, most of which are located primarily in Dimmit and Atascosa counties in Texas. Our acreage in the Eagle Ford play produced approximately 11,000 BOEPD (52% oil and 24% NGLs) during the fourth quarter of 2014.

China. Approximately 23 MMBOE, or 4%, of our proved reserves are located in China. Our Pearl facility, located in the South China Sea, is currently producing oil from three wells. An additional four wells are planned that will require net capital investments in 2015 of approximately $40 million. The Pearl facility is expected to reach peak production by mid-2015. Previously, our China assets were included in discontinued operations as they were being marketed for sale. In December 2014, after not being able to obtain an acceptable offer for our China business due to the substantial decline in commodity prices, we decided to retain the assets. Accordingly, the China business was reclassified to continuing operations during the fourth quarter of 2014.

Other. Over the last several years, we slowed our activities in our conventional natural gas plays and have sold numerous non-strategic assets. As of December 31, 2014, our conventional onshore plays in Texas produced approximately 5,700 BOEPD, consisting of 200 BOPD of oil, 300 BOEPD of NGLs and 31 MMcf/d of natural gas. We expect our production in these conventional plays to continue to experience natural declines in 2015 due to limited investment.

Divestitures

Over the last three years, we have divested over $2.1 billion of non-strategic assets in order to re-align our strategic focus toward liquids-rich resource plays in the United States, reduce overall debt and enhance liquidity. In conjunction with our continued portfolio management strategy, we sold or closed the sale of certain assets in 2014 as described below.

Granite Wash. In September 2014, we closed on the sale of our Granite Wash assets, located primarily in Texas, for approximately $588 million (subject to customary purchase price adjustments). We used proceeds from the Granite Wash sale to repay outstanding debt. Please see discussion in Note 4, “Oil and Gas Assets,” to our consolidated financial statements in Item 8 of this report.

Malaysia. In February 2014, Newfield International Holdings, Inc., a wholly-owned subsidiary of the Company, closed the sale of our Malaysia business to SapuraKencana Petroleum Berhad, a Malaysian public company, for $898 million. We used proceeds from the sale of our Malaysia business to fund capital expenditures during 2014. Please see discussion in Note 3, “Discontinued Operations,” to our consolidated financial statements in Item 8 of this report.

Reserves

Estimates of Proved Reserves

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates is completed in accordance with our prescribed internal control procedures, which include verification of data input into our reserves forecasting and economics evaluation software, as well as multi-discipline management reviews, as described below. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 30 years of experience (including over 20 years of experience in reserve estimation).

Our reserves estimates are made using available geological and reservoir data as well as production performance data. These estimates, made by our petroleum engineering staff, are reviewed annually with management and revised, either upward or downward, as warranted by additional data. The data reviewed includes, among other things, seismic data, well logs, production tests, reservoir pressures, and individual well and field performance data. The data incorporated into our interpretations includes structure and isopach maps, individual well and field performance and other engineering and geological work products such as material balance calculations and reservoir simulation to arrive at conclusions about individual well and field projections. Additionally, offset performance data, operating expenses, capital costs and product prices factor into estimating quantities of reserves. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental regulations, as well as changes in the expected recovery rates associated with development drilling. Sustained decreases in prices, for example, may cause a reduction in some reserves due to reaching economic limits sooner.

Actual quantities of reserves recovered will most likely vary from the estimates set forth below. Reserves and cash flow estimates rely on interpretations of data and require assumptions that may be inaccurate. For a discussion of these interpretations and assumptions, see “Actual quantities of oil, gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates” under Item 1A, “Risk Factors,” of this report. See “Supplementary Financial Information — Supplementary Oil and Gas Disclosures” in Item 8 of this report for additional reserves disclosures.

At year-end 2014, we had proved reserves of 645 MMBOE, 5% higher than year-end 2013. The table below summarizes our proved reserves by area at December 31, 2014.

	Proved Reserves (MMBOE)	Percentage of Proved Reserves	
Domestic:			
Mid-Continent	294	46	%
Rocky Mountains	280	43	%
Onshore Gulf Coast	48	7	%
Total Domestic	622	96	%
International:			
China	23	4	%

Total	645	100	%

The following table shows by country and in the aggregate a summary of our proved oil and gas reserves as of December 31, 2014.

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
Proved Developed Reserves:				
Domestic	135	938	38	329
China	9	—	—	9
Total Proved Developed	144	938	38	338
Proved Undeveloped Reserves:				
Domestic	143	669	38	293
China	14	—	—	14
Total Proved Undeveloped	157	669	38	307
Total Proved Reserves	301	1,607	76	645

Total Proved Reserves

Our estimates of proved reserves and related PV-10 and standardized measure of future net cash flows as of December 31, 2014 are calculated based upon SEC pricing, which uses a twelve-month unweighted average first-day-of-the-month oil and natural gas benchmark prices, adjusted for marketing and other differentials. The prices of crude oil, domestic natural gas and NGLs have declined substantially since June 2014. Sustained lower prices will result in future SEC pricing being substantially lower, which, absent significant proved reserve additions and/or cost reductions, will reduce future estimated proved reserve volumes due to lower economic limits and economic return thresholds for undeveloped reserves, as well as impact our quarterly full cost impairment ceiling tests and volume-dependent depletion cost calculations.

Our year-end 2014 proved reserves of 645 MMBOE consisted of 291 MMBOE proved developed producing, 47 MMBOE proved developed non-producing and 307 MMBOE proved undeveloped reserves. Our proved liquids reserves at year-end 2014 were 377 million barrels, compared to 338 million barrels at year-end 2013, an increase of 12%. During 2014, oil and condensate reserves increased 31 million barrels and NGL reserves increased 8 million barrels. At year-end 2014, 80% of our proved liquids reserves were crude oil or condensate. At December 31, 2014, our proved natural gas reserves were 1,607 Bcf, which represented a decrease of 2% compared to 2013.

During 2014, we added 72 MMBOE through extensions, discoveries and other additions. Consistent with our continued focus on domestic liquids, our 2014 additions were 99% domestic and 74% were liquids, which was 42 million barrels of oil and 12 million barrels of NGLs. Through infill drilling revisions, we added 77 MMBOE. At December 31, 2014, the SEC pricing for natural gas was $4.35 per MMBtu, a 19% increase compared to the prior year-end, and pricing for oil was $94.98 per barrel, a 2% decrease compared to the prior year-end. As a result, we revised our total proved reserves upward by 3 MMBOE for pricing changes. During 2014, we purchased 9 MMBOE and divested 49 MMBOE. Divestitures included 38 MMBOE in the Granite Wash and 10 MMBOE in Malaysia. During 2014, we had a negative 29 MMBOE performance revision primarily associated with the Arkoma Woodford, the Greater Monument Butte Unit and the Uinta's Wasatch formation.

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2014 were 307 MMBOE compared to 275 MMBOE at December 31, 2013. Liquids comprised 64% of our total proved undeveloped reserves as of December 31, 2014. During 2014, we invested approximately $0.8 billion of drilling, completion and facilities-related capital to convert 60 MMBOE of our December 31, 2013 proved undeveloped reserves into proved developed reserves. During 2014, we added 52 MMBOE of new proved undeveloped reserves through discoveries, extensions and other additions. In 2014, we had positive revisions of 34 MMBOE that were primarily related to successful infill drilling in our large onshore areas such as the Anadarko Basin offset by development plan updates. During 2014, we had a 6 MMBOE net increase due to sales and acquisitions. We continually assess the economic viability of our proved undeveloped reserves and direct capital resources to develop the areas that will provide the greatest stockholder value.

Proved undeveloped reserve quantities are limited by the activity level of development drilling we have intent to undertake during the 2015-2019 five-year period. We have estimated capital expenditures of approximately $575 million to develop our proved undeveloped reserves in 2015 in our reserve report as of December 31, 2014, which is consistent with our 2015 capital budget. Of the 307 MMBOE of proved undeveloped reserves at December 31, 2014, 39 MMBOE is associated with the Greater Monument Butte waterflood and exceed five years from the date of first booking. The waterflood requires the timely and orderly drilling of production and water injection wells, conversion of producing wells to injection wells and the injection of certain amounts of water before all producing wells are drilled to optimize oil recovery and project economics. For additional information regarding the changes in our proved reserves, see our "Supplementary Financial Information — Supplementary Oil and Gas Disclosures" under Item 8 of this report.

During the years 2012, 2013 and 2014, we developed 9%, 12% and 22%, respectively, of our prior year-end proved undeveloped reserves. The development plans in our year-end reserve report reflect (i) the allocation of capital to projects in the first year of activity based upon the initial budget for such year and (ii) in subsequent years, the capital allocation in our five-year business plan, each of which generally is governed by our expectations for capital investment in such time period. Changes in commodity pricing between the time of preparation of the reserve report and actual investment, investment alternatives that may have been added to our portfolio of assets, changes in the availability and costs of oilfield services, and other economic factors may lead to changes in our development plans. As a result, the future rate at which we develop our proved undeveloped reserves may vary from historical development rates. Continued sustained low oil and natural gas prices through 2015 could also render some of our proved undeveloped reserves uneconomic at SEC pricing or compel us to reevaluate our project commitments to certain development projects.

Reserves Sensitivities

Our year-end 2014 reserve estimates were prepared using SEC pricing for crude oil of $94.98 per barrel and natural gas of $4.35 per MMBtu. The current forward curve for commodity prices is materially lower compared to year-end 2014 SEC pricing; therefore, the following sensitivity table is provided to illustrate the estimated impact on our proved reserve volumes and value. In addition to different price assumptions, the sensitivities below include assumed capital and expense reductions we expect to realize at lower commodity prices. The reduction in proved reserve volumes is attributable to reaching the economic limit sooner. The proved undeveloped change in volumes is a result of well locations no longer meeting our investment criteria as well as reaching the economic limit sooner.

These sensitivity cases are only to demonstrate the impact that a lower price and cost environment may have on reserves volumes and PV-10. There is no assurance that these prices or cost savings will actually be achieved.

	Actual at December 31, 2014	Sensitivity A	Sensitivity B
Crude oil price (per Bbl)	$ 94.98(1)	$ 70.00(2)	$ 60.00(2)
Natural gas price (per MMBtu)	$ 4.35(1)	$ 4.00(2)	$ 3.50(2)
Capital expenditure reduction	n/a	25 %	25 %
Operating expense reduction	n/a	15 %	15 %
Proved developed reserves (MMBOE)	338	335	328
Proved undeveloped reserves (MMBOE)	307	299	266
Total proved reserves (MMBOE)	645	634	594
Proved reserve PV-10 value (before tax, in millions)	$ 8,787	$ 6,210	$ 4,472
Present value of future income tax expense	2,575	1,399	713
Standardized measure of discounted future net cash flows	$ 6,212	$ 4,811	$ 3,759

(1) SEC pricing before adjustment for market differentials.

(2) Prices represent potential SEC pricing based on different pricing assumptions before adjustment for market differentials.

PV-10 is a non-GAAP financial measure and generally differs from the standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented under U.S. generally accepted accounting principles), because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor the standardized measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific income tax characteristics of such entities. The following table shows a reconciliation of PV-10 to the standardized measure:

	Continuing Operations		Discontinued Operations	
	Domestic	China	Malaysia	Total
	(In millions)			
December 31, 2014:				
Proved reserve PV-10 value (before tax)	$7,723	$1,064	$—	$8,787
Present value of future income tax expense	2,393	182	—	2,575
Standardized measure of discounted future net cash flows	$5,330	$882	$—	$6,212
December 31, 2013:				
Proved reserve PV-10 value (before tax)	$6,637	$1,135	$303	$8,075
Present value of future income tax expense	2,009	233	—	2,242
Standardized measure of discounted future net cash flows	$4,628	$902	$303	$5,833

Reserves Concentration

The table below sets forth the concentration of our proved reserves attributable to our largest fields (those whose reserves are greater than 15% of our total proved reserves). Our largest fields by volume, SCOOP, the Greater Monument Butte Unit and Arkoma Woodford Shale, accounted for approximately 48% of the total net present value of our proved reserves at December 31, 2014.

	Percentage of Proved Reserves
10 largest fields	91%
3 largest fields	61%

Largest Fields. The table below sets forth the annual production volumes, average realized prices and related production cost structure on a per unit-of-production basis for our largest fields. For a discussion regarding our total domestic and international annual production volumes, average realized prices, related cost structure and information about our contractual obligations and delivery commitments, see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” which disclosure is incorporated herein by reference.

	Year Ended December 31,		
	2014	2013	2012
Production:			
Crude oil and condensate (MBbls)			
SCOOP	2,548	1,323	379
Greater Monument Butte Unit	4,062	3,764	3,720
Arkoma Woodford Shale	44	65	130
Natural gas (Bcf)			
SCOOP	34.5	16.8	5.1
Greater Monument Butte Unit	1.2	0.5	1.9
Arkoma Woodford Shale	41.7	51.7	63.2
NGLs (MBbls)			
SCOOP	4,762	1,888	653
Greater Monument Butte Unit	150	152	133
Arkoma Woodford Shale	67	75	86
Total production by field (MBOE)			
SCOOP	13,066	5,999	1,857
Greater Monument Butte Unit	4,411	4,001	4,172
Arkoma Woodford Shale	7,057	8,746	10,755
Average Realized Prices:[1]			
Crude oil and condensate (per Bbl)			
SCOOP	$85.66	$93.75	$86.03
Greater Monument Butte Unit	74.40	78.24	77.58
Arkoma Woodford Shale	90.44	93.71	90.54
Natural gas (per Mcf)			
SCOOP	$3.96	$3.35	$2.33
Greater Monument Butte Unit	4.09	4.74	1.71
Arkoma Woodford Shale	4.08	3.31	2.35
NGLs (per Bbl)			
SCOOP	$29.54	$31.62	$25.16
Greater Monument Butte Unit	48.33	52.26	63.92
Arkoma Woodford Shale	19.11	20.62	27.64
Average realized prices by field (per BOE)			
SCOOP	$37.94	$40.01	$32.73
Greater Monument Butte Unit	71.27	76.20	71.99
Arkoma Woodford Shale	24.82	20.43	15.14
Average Production Cost:			
SCOOP (per BOE)	$4.58	$4.38	$4.59
Greater Monument Butte Unit (per BOE)	25.68	24.14	16.48
Arkoma Woodford Shale (per BOE)	14.82	12.62	10.80

(1) Does not include impact of derivative gains or losses.

Drilling Activity

The following table sets forth the number of oil and gas wells that completed drilling for each of the last three years.

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive	254	114	297	118	263	135
Nonproductive	—	—	1	1	2	2
China:						
Nonproductive	1	1	1	1	—	—
Malaysia:(1)						
Productive	—	—	2	1	—	—
Nonproductive	—	—	—	—	2	1
Exploratory well total	255	115	301	121	267	138
Development wells:						
Domestic:						
Productive	326	231	237	184	240	195
China:						
Productive	2	1	3	1	—	—
Malaysia:(1)						
Productive	—	—	12	8	12	8
Development well total	328	232	252	193	252	203

(1) Classified as discontinued operations.

We were in the process of drilling 20 gross (15 net) development wells domestically at December 31, 2014. In China we were drilling one gross (one net) development well at December 31, 2014.

Productive Wells

As of December 31, 2014, we had the following productive oil and gas wells.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Oil	2,651	2,153	903	78	3,554	2,231
Natural gas	1,170	909	1,182	167	2,352	1,076
China:						
Oil	2	1	42	5	44	6
Total:						
Oil	2,653	2,154	945	83	3,598	2,237
Natural gas	1,170	909	1,182	167	2,352	1,076
Total	3,823	3,063	2,127	250	5,950	3,313

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions.

Acreage Data

The following two tables list by geographic area interests we owned in developed and undeveloped oil and gas acreage at December 31, 2014, along with a summary by year of our undeveloped acreage scheduled to expire in the next five years. In most cases, the drilling of a commercial well, or the filing and approval of a development plan or suspension of operations will hold the acreage beyond the expiration date. Domestic ownership interests are onshore and generally take the form of "working interests" in oil and gas leases that have varying terms. International ownership interests are offshore and generally arise from participation in PSCs.

Total Acreage

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Mid-Continent	814	286	344	210
Rocky Mountains	280	196	470	324
Onshore Gulf Coast	305	217	29	26
Total Domestic	1,399	699	843	560
China:	34	9	—	—
Total	1,433	708	843	560

Expiring Acreage

	Undeveloped Acres Expiring									
	2015		2016		2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Mid-Continent	62	39	70	40	37	24	1	—	—	—
Rocky Mountains	106	73	86	37	77	68	7	3	11	10
Onshore Gulf Coast	14	14	—	—	2	2	—	—	—	—

Total	182	126	156	77	116	94	8	3	11	10	13

At December 31, 2014, we owned fee mineral interests in 557,626 gross (121,561 net) acres. These interests do not expire.

Title to Properties

We believe that we have satisfactory title to substantially all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes, development obligations under oil and gas leases or capital commitments under our PSCs in China. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than that we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and gas industry. Generally, before we commence drilling operations on properties that we operate, we conduct a title examination and perform curative work with respect to significant defects that we identify. We believe that we have performed title examination with respect to substantially all of our active properties that we operate.

Marketing

Substantially all of our oil, natural gas and NGLs are sold at market-based prices to a variety of purchasers, primarily under short-term contracts (less than 12 months). We also have long-term contracts in the Uinta Basin at market-based prices, less a variable differential that becomes fixed below certain market price thresholds. For a list of purchasers of our production that accounted for 10% or more of our total revenues for the three preceding calendar years, please see Note 1, “Organization and Summary of Significant Accounting Policies — Major Customers,” to our consolidated financial statements in Item 8 of this report, which information is incorporated herein by reference. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers are available.

Historically, our access to refining capacity outside of the Salt Lake City area has been restricted due to limited transportation and refining options because of the paraffin content of our Uinta Basin production. As such, we have two long-term agreements with two refineries in the Salt Lake City area that run through 2020 and 2025. These agreements require us to deliver a combined 38,000 BOPD of crude oil. Since these agreements were entered into, developments in rail transportation in the area have reduced our dependence on the Salt Lake City refiners. Please see the discussion regarding potential delivery commitment shortfalls related to these agreements under "Contractual Obligations" in Item 7 of this report.

Competition

Competition in the oil and gas industry is intense, particularly with respect to the hiring and retention of technical personnel, the acquisition of properties and access to drilling rigs and other services. Please see the discussion under “Competition for, or the loss of, our senior management or experienced technical personnel may negatively impact our operations or financial results” and “Competition in the oil and gas industry is intense” in Item 1A of this report, which information is incorporated herein by reference.

Segment Information

For more information on our continuing operations by segment, see Note 14, “Segment Information,” to our consolidated financial statements in Item 8 of this report.

Employees

As of February 20, 2015, we had 1,331 employees. All but 61 of our employees were located in the United States. None of our employees are covered by a collective bargaining agreement. We believe that relationships with our employees are satisfactory.

Regulation

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, provincial, tribal, local, foreign and international regulations. An overview of these regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen resource or environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Please see the discussion under the caption “We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business,” in Item 1A of this report.

General Overview. Our oil and gas operations are subject to various federal, state, provincial, tribal, local, foreign and international laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- acquisition of seismic data;
- location of wells;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;
- drilling, casing and cementing of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production;
- spill prevention plans;
- protection of private and public surface and ground water supplies;
- emissions reporting, permitting or limitations;
- protection of endangered species and habitat;
- occupational safety and health;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- transportation of production; and
- export of natural gas.

Federal Regulation of Drilling and Production. Many of our domestic oil and gas leases are granted by the federal government and administered by the BSEE, ONRR or the BLM, all federal agencies. BLM leases contain relatively standardized terms and require compliance with detailed BLM, BSEE and ONRR regulations. Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the time during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban surface activity. Under certain circumstances, the BLM or the BSEE, as applicable, may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in a number of states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, disclosure of hydraulic fracturing fluid composition, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Environmental Regulations. We are subject to various federal, state, provincial, tribal, local, foreign and international laws and regulations concerning occupational safety and health, oil and gas production, as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials and flowback or produced water;
- the emission of certain gases or materials into the atmosphere;
- the construction and placement of wells;
- the monitoring, abandonment, reclamation and remediation of wells and other sites, including sites of former operations;
- various environmental reporting and permitting requirements;
- the development of emergency response and spill contingency plans;
- disclosure of chemicals used in hydraulic fracturing; and
- protection of private and public surface and ground water supplies.

We consider the costs of environmental regulatory compliance and protection and safety and health compliance necessary and manageable parts of our business. We have been able to plan for and comply with environmental regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increased stringency, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and will likely continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters and the cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations).

Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted or banned by governmental authorities. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of onshore or offshore drilling, or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

Discharges to waters of the U.S. are further regulated and limited under the federal Clean Water Act ("CWA") and analogous state and tribal laws. The CWA prohibits any discharge of pollutants into waters of the United States except in

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compliance with permits issued by federal and state governmental agencies. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure or “SPCC” plans. We have such plans in place and have made changes as necessary due to regulatory changes by the U.S. Environmental Protection Agency, also known as the “EPA,” that became effective in November 2009.

The National Environmental Policy Act, or NEPA, requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. Compliance with this requirement may lead to additional costs and delays in permitting for operators as the BLM may need to prepare additional Environmental Assessments and more detailed Environmental Impact Statements, which would be available for public review and comment. In addition, the White House Council on Environmental Quality recently issued draft guidance requiring consideration of climate change impacts in NEPA reviews, which may result in requirements to deploy additional air pollution control measures. These additional requirements could increase our compliance costs.

The Endangered Species Act restricts activities that may affect federally-identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal or permanent ban on operations in affected areas. Similarly, the Migratory Bird Treaty Act, or MBTA, implements various treaties and conventions between the U.S. and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas.

The Resource Conservation and Recovery Act, or RCRA, generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste “drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy,” the EPA and state agencies may regulate these wastes as solid wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a “hazardous substance” into the environment. Such “responsible parties” may be subject to joint and several liability under the Superfund law for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease onshore properties that have been used for the exploration and production of oil and natural gas for a number of years. Many of these onshore properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been disposed or released on them may be subject to the Superfund law, RCRA and analogous state laws and common law obligations, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

The Clean Air Act, or CAA, and comparable state statutes regulate and limit the emission of air pollutants by the Company and affect our oil and gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed and continues to develop more stringent regulations governing emissions of toxic air pollutants, and is considering the expanded regulation of existing air pollutants and additional air pollutants. In addition, the EPA promulgated regulations that are designed to reduce the emission of volatile organic chemicals (VOCs) and that will require oil and gas companies by 2015 to utilize "green completions" to capture VOCs and other air pollutants when natural gas wells are fracked. Such regulations may increase the costs of compliance for some facilities or the market price for oil and natural gas.

In addition, while the federal Safe Drinking Water Act, or SDWA, generally excludes hydraulic fracturing from the definition of underground injection, it does not exclude hydraulic fracturing involving the use of diesel fuels. In 2014, the EPA issued draft permitting guidance governing hydraulic fracturing with diesel fuels. While we do not use diesel fuels in our hydraulic fracturing fluids, we may become subject to federal permitting under SDWA if our fracturing formula changes. In addition, the SDWA grants the EPA broad authority to take action to protect public health when an underground source of drinking water is threatened with pollution that presents an imminent and substantial endangerment to humans.

The Occupational Safety and Health Act, or OSHA, and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

For more than a decade, Congress has been considering a variety of sectoral or economy-wide market-based tax, energy or environmental mechanisms to regulate or induce the reduction of emissions of greenhouse gases by several commercial or industrial sectors. In June of 2009, the U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009. In addition, more than one-third of the states have implemented some form of legal measure to regulate or reduce emissions of greenhouse gases. On April 2, 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an “air pollutant” under the CAA. On December 7, 2009, the EPA responded to the Massachusetts, et al. v. EPA decision with an “endangerment finding” for greenhouse gases emitted from certain mobile sources. The EPA finding concluded that such GHG emissions “cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare” and contribute to the threat of climate change.

In 2013, the United States Court of Appeals for the District of Columbia Circuit upheld, in Coalition for Responsible Regulation, Inc. v. EPA, the EPA endangerment finding. On October 15, 2013, the United States Supreme Court declined to review the EPA’s endangerment finding or its underlying scientific conclusions, as well as the regulations governing emissions of GHGs from motor vehicles, but granted review on several stationary source permitting issues under the CAA. By leaving the endangerment finding undisturbed, the Court has effectively affirmed the EPA’s authority to regulate GHGs under the CAA.

In June 2013, the President of the United States released a Climate Action Plan which sets forth a series of executive actions the current administration intends to undertake to address climate change. The Climate Action Plan includes a two-part directive that the EPA promulgate rules to regulate GHG emissions from new and existing fossil fuel power plants on a defined schedule and consider employing market-based mechanisms. Specifically, the President issued a Presidential Memorandum directing the EPA to propose and timely finalize carbon emission standards for certain new fossil fuel power plants under Section 111(b) of the CAA, and to propose carbon emission “standards, regulations or guidelines” for existing fossil fuel power plants under Section 111(d) of the CAA. The EPA intends to promulgate final carbon standards for new and existing fossil fuel power plants by mid-2015. The rule for existing sources, in particular, may require states to develop plans to maintain “greenhouse gas budgets” under certain thresholds. As a result, states may seek to impose additional air requirements on oil and gas operations to meet these budgets. The EPA also announced in January 2015 that it would be issuing methane regulations for the oil and gas industry by mid-2015. We do not yet know what such regulations would require or how they might impact our operations.

Several other federal agencies and state governments are considering or have already implemented rules to regulate, monitor, or induce market reductions of GHG emissions. It is not possible at this time, however, to predict the applicability or stringency of future GHG mitigation regulations for the oil and gas industry, if at all, or how any new legislation or regulations would impact our business. Any such future federal laws and regulations could affect oil and natural gas commodity market pricing, and result in increased costs of compliance, or additional operating restrictions. Any additional costs or operating restrictions associated with GHG legislation or regulations could have material adverse effects on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

In addition, federal, state, tribal and local agencies are considering or have already implemented regulations related to hydraulic fracturing. Hydraulic fracturing involves using water, sand, and certain chemicals pumped at high pressure to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The hydraulic-fracturing process is typically regulated by state oil and natural gas agencies, although the EPA and other federal regulatory agencies have taken steps to impose federal regulatory requirements. Certain states in which we operate or own interests, such as Texas, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether.

For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process, and the RCT adopted rules regarding the same in December 2011. We currently voluntarily disclose all chemicals used in our hydraulic fracturing through FracFocus (http://fracfocus.org), the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission, two organizations whose missions both revolve around conservation and environmental protection. Nevertheless, in May 2014, the EPA published an Advanced Notice of Proposed Rulemaking under the Toxic Substances Control Act to develop a federal approach to obtain information on chemical substances and mixtures used in hydraulic fracturing.

Federal Regulation of Sales and Transportation of Natural Gas. Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

Pursuant to authority delegated to it by the Energy Policy Act of 2005, or EPAct 2005, FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms which make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to use or employ any device, scheme, or artifice to defraud, to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity. Violation of these requirements, similar to violations of other NGA and FERC enforcement authorities, may be subject to investigation and penalties of up to $1 million per day per violation. FERC may also order disgorgement of profit and corrective action. We believe, however, that neither the EPAct 2005 nor the regulations promulgated by FERC as a result of the EPAct 2005 will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Our sales of oil and natural gas are also subject to anti-manipulation and anti-disruptive practices authority under the Commodity Exchange Act, or CEA, as amended by the Dodd-Frank Wall Street Reform Act and Consumer Reform Act (the Dodd-Frank Act), and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA, as amended by the Dodd-Frank Act, prohibits any person from using or employing any manipulative or deceptive device in connection with any swap, or a contract of sale of any commodity, or for future delivery on such commodity, in contravention of the CFTC's rules and regulations. The CEA, as amended by the Dodd-Frank Act, also prohibits knowingly delivering or causing to be delivered false or misleading or inaccurate reports concerning market information or conditions that affect or tend to affect the price of any commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the EPA, the FERC, the CFTC and the courts. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. There is always some risk, however, that Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action the FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by the FERC and Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other crude oil and condensate producers. In addition, certain emergency orders issued in 2014 by the U.S. Department of Transportation imposed additional restrictions on the shipment of crude oil by rail from the

Bakken Shale. These new restrictions may increase our costs of transporting our production from the Bakken.

International Regulations. Our exploration and production operations in China are subject to various types of regulations similar to those described above. These regulations are imposed by various agencies under the People's Republic of China (PRC). For example, laws under the Provisional Regulations on Administration and Management of the Abandonment of Offshore Oil and Gas Producing Facilities enacted in 2010, regulate our development and production activities offshore China. There are several departments in charge of aspects of energy industry regulation in China, including, the Bureau of Energy, the Ministry of Land and Resources, the Ministry of Housing and Urban-Rural Development, the State Administration of Work Safety, the Ministry of Environmental Protection, and the State Bureau of Tax. The PRC continues to develop environmental laws, regulations and controls surrounding offshore developments. In many cases, the legal requirements may be similar in form to the U.S. regulations; however, they impose additional or more stringent conditions or controls that can significantly alter or delay the development of a project or substantially increase the cost of doing business in China.

Financial Information

Financial information regarding the geographic areas in which we operate is incorporated herein by reference to Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 8, “Financial Statements and Supplementary Data.” Risks associated with our international operations are discussed under Item 1A, "Risk Factors," which information is incorporated herein by reference.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business and in this report.

Barrel or Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular derivative transaction.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

BLM. The Bureau of Land Management of the United States Department of the Interior.

BOE. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate or 42 gallons for NGLs.

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

BSEE. Bureau of Safety and Environmental Enforcement.

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.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Developed acres. The number of acres that 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 gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploitation activities. An exploration well drilled to find and produce probable reserves. Exploitation wells typically have less risk and less reserve potential and may be drilled at a lower cost than other exploration wells. Most of the exploitation wells we drill are located in the Mid-Continent or the Monument Butte field. For internal reporting and budgeting purposes, we combine exploitation and development activities.

Exploration well. An exploration well is a well drilled to find a new field or new reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well. For internal reporting and budgeting purposes, we exclude exploitation activities from exploration activities.

FERC. The Federal Energy Regulatory Commission.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

FPSO. A floating production, storage and off-loading vessel commonly used overseas to produce oil from locations where pipeline infrastructure is not available.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

Infill drilling or infill well. A well drilled between known producing wells to improve oil and gas reserve recovery efficiency.

Liquids. Crude oil and NGLs.

Liquids-rich. Formations that contain crude oil or NGLs instead of, or as well as, natural gas.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

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

MMBOE. One million barrels of oil equivalent, which includes crude oil and condensate, NGLs and natural gas. One MMBOE equals six Bcf.

MMBtu. One million Btus.

MMcf. One million cubic feet of natural gas.

MMcf/d. One million cubic feet of natural gas produced per day.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

MMMBtu. One billion Btus.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells.

NGL. Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasolines.

NYMEX. The New York Mercantile Exchange.

NYMEX Henry Hub. The major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

ONRR. Office of Natural Resources Revenue.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered. The SEC provides a complete definition of probable reserves in Rule 4-10(a)(18) of Regulation S-X.

Productive well.   A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves.   In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved undeveloped reserves. In general, 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. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

PV-10. The pre-tax present value of estimated future gross revenues from the production of proved reserves, based on year-end SEC pricing, net of estimated future production, development and abandonment costs, based on year-end costs, discounted at an annual discount rate of 10%. After-tax PV-10 is referred to as the standardized measure.

Reserve life index. This index is calculated by dividing total proved reserves on an equivalent basis at year-end by annual production to estimate the number of years of remaining production.

Resource play. A play targeting tight sand, coal bed or shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require horizontal drilling and stimulation treatments or other special recovery processes in order to be produced economically.

SCOOP. South-Central Oklahoma Oil Province. A field in the Anadarko Basin of Oklahoma in which we operate.

SEC pricing. The unweighted average first-day-of-the-month commodity price for crude oil (WTI) or natural gas (NYMEX) for the prior 12 months, adjusted for market differentials. The SEC provides a complete definition of prices in “Modernization of Oil and Gas Reporting” (Final Rule).

STACK. Sooner Trend Anadarko Canadian Kingfisher. A play in the Anadarko Basin of Oklahoma in which we operate.

Tcf. One trillion cubic feet of natural gas.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production and requires the owner to pay a share of the costs of drilling and production operations.

WTI. West Texas Intermediate, a grade of crude oil.

Additional Information

Through our website, www.newfield.com, you can access electronic copies of our governing documents free of charge, including our Board of Directors’ Corporate Governance Guidelines and the charters of the committees of our Board of Directors. In addition, through our website, you can access the documents we file with the U.S. Securities and Exchange Commission (SEC), including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments thereto, as soon as reasonably practicable after we file or furnish them. You also may request printed copies of our SEC filings or governance documents, free of charge, by writing to our corporate secretary at the address on the cover of this report. Information contained on our website is not incorporated herein by reference and should not be considered part of this report.

In addition, the public may read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Our corporate headquarters are located at 4 Waterway Square Place, Suite 100, The Woodlands, Texas 77380, and our telephone number is (281) 210-5100.

Item 1A. Risk Factors

There are many factors that may affect Newfield's business and results of operations. Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. You should carefully consider, in addition to the other information contained in this report, the risks described below.

Oil, gas and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth, as well as liquidity and ability to access additional sources of capital, depend substantially on prevailing prices for oil, gas and NGLs. Sustained lower prices will reduce the amount of oil, natural gas and NGLs that we can economically produce. Oil, natural gas and NGL prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital.

The markets for oil, gas and NGLs have historically been, and will likely remain, volatile. For example, record high U.S. crude oil production has contributed to global oil supply exceeding demand, which has caused crude oil prices to drop precipitously since September 2014. The price of crude oil (WTI) in January 2015 averaged approximately $47 per barrel, as compared to approximately $95 per barrel in January 2014. Natural gas prices also experienced significant volatility during 2014, as the NYMEX Henry Hub natural gas price ranged from a high of $6.15 per MMBtu (the highest price since December 2008) to a low of $2.89 per MMBtu (on the last trading day of the year).

The market prices for crude oil, natural gas and NGLs depend on factors beyond our control. Among the factors that can cause fluctuations are:

- the domestic and foreign supply of, and demand for, oil, natural gas and NGLs;
- world-wide economic conditions;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- political conditions in oil and gas producing regions;
- the actions taken by foreign oil and gas producing nations;
- the actions taken by the Organization of Petroleum Exporting Countries;
- the price and availability of, and demand for, alternative fuels;
- weather conditions and climate change;
- world-wide conservation measures;
- technological advances affecting energy consumption;
- the price and level of foreign imports;
- potential U.S. exports of oil and/or NGLs;
- the availability, proximity and capacity of transportation and processing facilities;
- the costs of exploring for, developing, producing, transporting and marketing oil, gas and NGLs; and
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulation.

While we cannot predict whether or for how long commodity prices will remain at this level or decline further, we have made adjustments in response to the current strong supply and soft demand, such as modifying our 2015 capital investment plan based on commodity prices, drilling success, and markets for our products. These adjustments are likely to influence our profitability and could adversely affect our business, financial condition and results of operations. In addition, our stock price in the market is influenced by oil and gas price movements.

Sustained material declines in crude oil, natural gas or NGL prices may have the following effects on our business:

•limit our access to sources of capital, such as equity and long-term debt;
•cause us to delay or postpone capital projects;
•cause us to lose certain leases because we fail to develop the leases prior to expiration;
•reduce reserves and the amount of products we can economically produce;
•reduce revenues, income and cash flows; or
•reduce the carrying value of our assets in our balance sheet through ceiling test impairments.

We have substantial capital requirements to fund our business plans that could be greater than cash flows from operations. Limited liquidity would likely negatively impact our ability to execute our business plan. We anticipate that our 2015 capital investment levels will approximate our cash flows from operations (inclusive of realized derivative contract gains and losses). We expect to use available capacity under our credit arrangements to fund any shortfall. Our ability to generate operating cash flows is subject to many risks and variables, such as the level of production from existing wells; prices of natural gas, oil and NGLs; our success in developing and producing new reserves and the other risk factors discussed herein. Actual levels of capital expenditures may vary significantly due to many factors including drilling results, commodity prices, industry conditions, the prices and availability of goods and services, the extent to which properties are acquired and the promulgation of new regulatory requirements. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We may have to reduce capital expenditures, and our ability to execute our business plans could be adversely affected, if:

•we are unable to access the capital markets at a time when we would like, or need, to raise capital;
•one or more of the lenders under our existing credit arrangements fails to honor its contractual obligation to lend to us;
•investors limit funding or refrain from funding fossil fuel companies;
•our customers or working interest owners default on their obligations to us; or
•we are unable to sell non-strategic assets at acceptable prices due to low commodity prices.

Actual quantities of oil, natural gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates. Estimating accumulations of oil, natural gas and NGLs is complex and inexact. The process relies on interpretations of geologic, geophysical, engineering and production data. The extent, quality and reliability of these data can vary. The process also requires a number of economic assumptions, such as oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, the effect of government regulation, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

•the quality and quantity of available data;
•the interpretation of that data;
•the accuracy of various mandated economic assumptions and our expected development plan; and
•the judgment of the persons preparing the estimate.

The proved reserve information set forth in this report is based on our prepared estimates. Estimates prepared by others might differ materially from our estimates.

Actual quantities of oil, natural gas and NGL reserves, future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures and operating expenses will most likely vary from our estimates. In addition, the methodologies and evaluation techniques that we use, which include the use of multiple technologies, data sources and interpretation methods, may be different than those used by our competitors. Further, reserve estimates are subject to the evaluator's criteria and judgment and show important variability, particularly in the early stages of development. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of reserves to reflect production history, results of exploration and development activities, prevailing oil, natural gas and NGL prices and other factors, many of which are beyond our control. Our reserves also may be susceptible to drainage by operators on adjacent properties.

You should not assume that the present value of future net cash flows is the current market value of our proved reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on SEC 12-month average pricing, adjusted for market differentials and costs in effect at year-end discounted at 10%. Actual future prices and costs may be materially higher or lower than the prices and costs we used as of the date of an estimate. In addition, actual production rates for future periods may vary significantly from the rates assumed in the calculation.

To maintain and grow our production and cash flows, we must continue to develop existing reserves and locate or acquire new reserves. Through our drilling programs and the acquisition of properties, we strive to maintain and grow our production and cash flows. However, as we produce from our properties, our reserves decline. Unless we successfully replace the reserves that we produce, the decline in our reserves will eventually result in a decrease in gas and oil production and lower revenues and cash flows from operations. Future natural gas and oil production is, therefore, highly dependent on our success in efficiently finding, developing or acquiring additional reserves that are economically recoverable. We may be unable to find, develop or acquire additional reserves or production at an acceptable cost, if at all. In addition, these activities require substantial capital expenditures.

Lower oil and gas prices and other factors have resulted in ceiling test writedowns in the past and based upon current commodity prices, will result in future ceiling test writedowns or other impairments. We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into cost centers that are established on a country-by-country basis. The net capitalized costs of our oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties. If net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, a ceiling test writedown reduces earnings and stockholders' equity in the period of occurrence. We evaluate the ceiling test quarterly and had our last ceiling test writedown of approximately $1.5 billion ($948 million, after tax) at December 31, 2012. We did not have a ceiling test writedown in 2013 or 2014; however, due to the substantial decline of commodity prices during the fourth quarter of 2014, which has continued so far during the first quarter of 2015, we anticipate that we will have a ceiling test writedown during the first quarter of 2015. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, upward or downward reserve revisions, reserve adds, and tax attributes. Subject to these numerous factors and inherent limitations, we believe that an impairment in the first quarter of 2015 could exceed $750 million. Once recorded, a ceiling test writedown is not reversible at a later date even if oil and gas prices increase.

The risk that we will be required to further writedown the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, writedowns may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase.

Drilling is a high-risk activity. In addition to the numerous operating risks described in more detail below, the drilling of wells involves the risk that no commercially productive oil or gas reservoirs will be encountered. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. In addition, we are often uncertain of the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- decreases in oil and gas prices;
- adverse weather conditions and changes in weather patterns;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- surface access restrictions;
- access to, and costs for, water needed in our waterflood project in the GMBU;

- the presence of underground sources of drinking water, previously unknown water or other extraction wells or endangered or threatened species;
- embedded oilfield drilling and service tools;
- equipment failures or accidents;
- lack of necessary services or qualified personnel;
- availability and timely issuance of required governmental permits and licenses;
- loss of title and other title-related issues;
- availability, costs and terms of contractual arrangements, such as leases, pipelines and related facilities to gather, process and compress, transport and market natural gas, crude oil and related commodities; and
- compliance with, or changes in, environmental, tax and other laws and regulations.

Future drilling activities may not be successful, and if unsuccessful, this could have an adverse effect on our future results of operations and financial condition.

The oil and gas business involves many operating risks that can cause substantial losses. Our oil and gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the risk of:

- fires and explosions;
- blow-outs and cratering;
- uncontrollable or unknown flows of oil, gas or well fluids;
- formations with abnormal pressures;
- pipe or cement failures and casing collapses;
- pipeline or other facility ruptures and spills;
- equipment malfunctions or operator error;
- adverse weather conditions or natural disasters;
- discharges of toxic gases;
- buildup of naturally occurring radioactive materials;
- vandalism;
- environmental costs and liabilities due to our use, generation, handling and disposal of materials, including wastes, hydrocarbons and other chemicals; and
- environmental damages caused by previous owners of property we purchase and lease.

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 occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property and equipment, and oil and gas reservoirs;
- pollution and other environmental damage;

- investigatory and clean-up responsibilities;
- regulatory investigation and penalties or lawsuits;
- limitation on or suspension of our operations; and
- repairs to resume operations.

Further, offshore operations are subject to a variety of additional operating risks, such as capsizing, collisions and damage or loss from typhoons or other adverse weather conditions. These conditions could cause substantial damage to facilities and interrupt production. Our China operations are dependent upon the availability, proximity and capacity of gathering systems and processing facilities that we do not own. Necessary infrastructures have been in the past, and may be in the future, temporarily unavailable due to adverse weather conditions or other reasons, or they may not be available to us in the future on acceptable terms or at all.

Failure or loss of equipment, as the result of equipment malfunctions, cyber-attacks or natural disasters, could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Catastrophic occurrences giving rise to litigation, such as a well blowout, explosion or fire at a location where our equipment and services are used, may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture could result in extensive environmental pollution and substantial remediation expenses. If our production is interrupted significantly, our efforts at containment are ineffective or litigation arises as the result of a catastrophic occurrence, our cash flows, and in turn, our results of operations, could be materially and adversely affected.

In connection with our operations, we generally require our contractors, which include the contractor, its parent, subsidiaries and affiliate companies, its subcontractors, their agents, employees, directors and officers, to agree to indemnify us for injuries and deaths of their employees, contractors, subcontractors, agents and directors, and any property damage suffered by the contractors. There may be times, however, that we are required to indemnify our contractors for injuries and other losses resulting from the events described above, which indemnification claims could result in substantial losses to us.

While we maintain insurance against some potential losses or liabilities arising from our operations, our insurance does not protect us against all operational risks. The occurrence of any of the foregoing events and any costs or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage or not indemnified, could reduce revenue and the funds available to us for our exploration, exploitation, development and production activities and could, in turn, have a material adverse effect on our business, financial condition and results of operations. See also "- We may not be insured against all of the operating risks to which our business is exposed."

We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business. Existing and potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development and the production and sale of oil, natural gas and NGLs are subject to extensive federal, state, provincial, tribal, local and international regulation. We may be required to make large expenditures to comply with environmental, habitat and other governmental regulations. Matters subject to regulation include the following, in addition to the other matters discussed under the caption "Regulation" in Items 1 and 2 of this report:

- the amounts, types and manner of substances and materials that may be released into the environment;
- response to unexpected releases into the environment;
- reports and permits concerning exploration, drilling, production and other operations;
- the placement and spacing of wells;
- cement and casing strength;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and

- taxation.

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Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs, natural resource risk mitigation, damages and other environmental or habitat damages. We also could be required to install and operate expensive pollution controls, engage in environmental risk management and derivative activities or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. In addition, failure to comply with applicable laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition, results of operations or cash flows.

Further, changes to existing environmental regulations or the adoption of new regulations may unfavorably impact us, the oil and gas industry generally, our suppliers or our customers. For example, governments around the world have become increasingly focused on regulating greenhouse gas (GHG) emissions and addressing the impacts of climate change in some manner. In the absence of dedicated federal legislation on climate change mitigation or adaptation, the U.S. Environmental Protection Agency (EPA) has promulgated several rulemakings to regulate, measure or monitor GHG emissions under the existing provisions of the Clean Air Act, or CAA. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, as well as from certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis. The new regulations could impact certain facilities in which we have interests (legal, equitable, operated or non-operated) by increasing regulatory risks and reporting requirements.

In December 2009, the EPA issued an “endangerment finding” under the CAA concluding that the current and projected concentrations of GHGs in the atmosphere from motor vehicles threaten the public health and welfare of current and future generations. The finding, once made, required the EPA to begin regulating GHG emissions from new cars and light trucks under the CAA. Indirectly, the EPA argued that it also triggered an EPA obligation to regulate GHG emissions under existing relevant air permitting programs for large stationary sources. On January 2, 2011, the EPA initiated Prevention of Significant Deterioration (PSD) permitting requirements for carbon dioxide and other GHGs from large and modified stationary sources. Permits limiting GHGs have been issued for a variety of new or modified facilities under the Clean Air Act PSD program. GHG emissions also trigger Title V operating permit requirements for new and existing sources that exceed certain established emission thresholds. Emission levels in excess of these thresholds can then trigger preconstruction permit requirements and application of best available control technology (BACT) or operation consistent with the lowest achievable emissions rate (LAER) as determined on a source-by-source basis.

In June 2014, the Supreme Court upheld most of the EPA’s GHG permitting requirements, allowing the agency to regulate the emission of GHGs from stationary sources already subject to the Clean Air Act’s prevention of significant deterioration (PSD) and Title V requirements. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and hence, under the Supreme Court’s ruling, also be subject to the installation of controls to capture GHGs. For any equipment or installation so subject, we may have to incur increased compliance costs to capture GHGs.

The EPA took additional action under the Clean Air Act in June 2014. In accordance with the President of the United States' Climate Action Plan, on June 18, 2014, the EPA proposed rules to reduce carbon emissions from electric generating units. The proposal, commonly called the “Clean Power Plan,” requires states to develop plans to reduce carbon emissions from fossil fuel-fired generating units, commencing in 2020, with the reductions to be fully phased in by 2030. Under the proposal, each state would be given a different carbon reduction target, but the EPA expects that, in the aggregate, the overall proposal will reduce carbon emissions from electric generating units by 30% from 2005 levels.

As proposed, states are given great flexibility in meeting their emission reduction targets, and can generally choose to lower carbon emissions by replacing higher carbon generation, such as coal or natural gas, with lower carbon generation, such as efficient natural gas units, renewable or end-use energy efficiency. It is not possible at this time to predict what requirements might be adopted by the EPA in the final rule, expected in 2015, or how any such final rule would impact our business.

Recently, the President of the United States announced that the EPA would propose by mid-2015, a new series of regulations to reduce methane emissions from the oil and gas industry by 2025 by about 40 to 45% from 2012 levels. These rules are in addition to a series of recent EPA oil and gas rules designed to curb volatile organic compound (VOC) emissions from natural gas wells and related equipment, such as storage vessels and glycol dehydrators.

If the U.S. Congress adopts market-based tax, energy or other mechanisms to regulate the carbon intensity of natural resources, or promote or require the reduction of GHG emissions from certain industrial sectors, such legislation, depending on design and scope, could increase the cost of oil and gas production and market demand. Some states, like California, have implemented state-wide GHG mitigation programs to reduce GHG emissions through a mixture of regulatory programs, including a low carbon fuel standard and cap-and-trade market applicable to, among others, electric utilities and transportation fuels.

Further, the U.S. Congress has previously proposed legislation that would directly impact our industry. In response to the 2010 Macondo incident in the Gulf of Mexico, the U.S. Congress considered a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations governing our operations in the United States, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

Some federal agencies are adopting new rules governing hydraulic fracturing on leased federal or tribal trust lands. Meanwhile, states, tribes and municipalities across the country have issued moratoria banning hydraulic fracturing. While we cannot predict how these rules will impact our business, they will likely increase costs or otherwise limit where we may conduct exploration and production activities.

In December 2014, the Council on Environmental Quality issued draft guidance on consideration of climate change in project reviews under the National Environmental Policy Act (NEPA). We do not know whether and when this guidance may become final, nor can we predict its likely impact on our business. It is possible, however, that closer consideration of climate change may require BLM or other federal agencies to require enhanced environmental protections, at increased costs to operations like ours, at hydraulic fracturing sites across the country.

These and other potential legislative proposals, along with any applicable legislation introduced and passed in Congress, could increase our costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows. See also “- The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.”

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the natural gas and other hydrocarbon products that we produce.

The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on almost all of our U.S. onshore oil and natural gas properties. Hydraulic fracturing involves using water, sand or other proppant materials, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the BLM and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Certain municipalities have already banned hydraulic fracturing, and courts have upheld those moratoria in some instances. In the past several years, dozens of states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing.

For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process, and the RCT promulgated rules regarding the same in December 2011. On September 11, 2012, the RCT approved new regulations relating to the commercial recycling of produced water and/or hydraulic-fracturing flowback fluid. In addition, in May 2013 the RCT adopted amendments to Statewide Rule 13 governing casing, cementing, well control and completion of oil and gas wells; these new construction requirements took effect on January 1, 2014.

In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. For example, on June 30, 2014, New York's highest state court upheld local zoning ordinances that ban hydraulic fracturing within municipal limits.

In the event state, local or municipal legal restrictions are adopted in areas where we are currently conducting operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells. Depending on the areas in which they are adopted, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

In addition, on July 3, 2014, major university and U.S. Geological Survey researchers published a study purporting to find a causal connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. This study may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

The EPA is also developing a proposed rule to amend the Effluent Limitations Guidelines for the Oil and Gas Extraction Category. The proposed rule is scheduled for publication in 2015. It is unclear what the proposed rule will require, but with potential future limits on deep well injection, these limits may become increasingly important, as extraction and production companies look to dispose of wastewater to publicly-owned treatment works or centralized waste treaters. If deep well injection is shut down or limited, and discharge to surface waters is impossible, we may face increased disposal costs.

In recent years, the federal government has increased its focus on the environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality has coordinated an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices involving the use of diesel fuel.

The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuels under the Safe Drinking Water Act and in February 2014 issued permitting guidance for hydraulic fracturing activities using diesel.

Further, on May 19, 2014, the EPA published an Advance Notice of Proposed Rulemaking (ANPR) under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties.

In addition, in May 2013, the Bureau of Land Management issued a proposed rule that would require the public disclosure of chemicals used in hydraulic fracturing operations, set requirements for well-bore integrity and establish flowback water standards for all hydraulic fracturing operations on federal public lands and American Indian Tribal lands. The proposed rule also required that an operator certify, in writing, that (a) the stimulation design complies with all federal, state, tribal and local regulations; (b) the stimulation was completed in accordance with the design approved by BLM and all applicable regulations; and (c) the well-bore integrity was maintained during the fracturing process and flowback water was properly stored, treated and disposed. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with draft results to be issued in 2015 for public comment and peer review.

In addition, the U.S. Department of Energy has conducted an investigation into practices to better protect the environment from drilling using hydraulic fracturing completion methods. In a November 18, 2011 report, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued 20 recommendations to federal agencies, states and private entities that are intended to reduce the environmental impact and assure the safety of shale gas production. The U.S. Department of Energy continues to work with other federal agencies to identify best practices for shale gas production. Some of these may become enforceable statutory or regulatory requirements that would likely increase our compliance costs.

Given the heightened awareness regarding the use of hydraulic fracturing, it is possible that regulatory agencies or private parties may suggest that hydraulic fracturing has caused groundwater or surface water contamination, whether or not such allegations are accurate. For example, on December 8, 2011, the EPA released a preliminary report indicating that hydraulic fracturing is responsible for groundwater contamination in Pavillion, Wyoming, although the EPA’s draft report has been vigorously criticized as ignoring certain facts and utilizing incorrect data. In addition, the EPA alleged in an enforcement action against an operator in Texas that the operator contaminated local groundwater wells, although the RCT found after an evidentiary hearing that the operator was not responsible for the contamination. However, in 2013 the EPA deferred the Pavillion matter to state oversight and withdrew the emergency action order in Texas. Nevertheless, energy extraction, with a focus on onshore natural gas production, remains an EPA enforcement initiative. Thus, regulatory agencies or private parties alleging groundwater contamination linked to hydraulic fracturing could trigger defense costs in administrative or civil litigation or proceedings to rebut the allegations.

Additionally, certain members of the Congress have called upon (a) the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, (b) the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and (c) the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Further, on August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA finalized rules under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA regulations include NSPS standards for completions of hydraulically-fractured gas wells.
Since January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAPS include specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. EPA has revised this rule two times, in September 2013 and December 2014. We have and continue to evaluate the effect of these regulations, including the latest revisions, on our business. Compliance with such regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Based on the foregoing, increased regulation and attention given to the hydraulic fracturing process from federal agencies, various states and local governments could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

We could be adversely affected by the credit risk of financial institutions. We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds and other institutions. In the event of default of a counterparty, we would be exposed to credit risks. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative contracts and insurance companies in the form of claims under our policies. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facility.

Our use of oil and natural gas price derivative contracts may limit future revenues from price increases and involves the risk that our counterparties may be unable to satisfy their obligations to us. As part of our risk management program, we generally use derivative contracts to protect a substantial, but varying, portion of our anticipated future oil and gas production for the next 24-36 months to reduce our exposure to fluctuations in oil and natural gas prices. As of December 31, 2014, we had no outstanding derivative contracts related to our NGL production. A significant portion of our crude oil derivative contracts include short puts. If market prices remain below our sold puts at contract settlement, we will receive the difference between our floors or swaps and the associated sold puts, effectively limiting the downside protection of these contracts. In the case of acquisitions, we may use derivative contracts to protect acquired production from commodity price volatility for a longer period. In addition, we may utilize basis contracts to hedge the differential between the relevant underlying commodity reference prices and those of our physical pricing points. While the use of derivative contracts may limit or reduce the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements and expose us to the risk of financial loss in certain circumstances. Those circumstances include instances where our production is less than the volume subject to derivative contracts or there is a widening of price basis differentials between delivery points for our production and the delivery points assumed in the derivative transactions.

The use of derivative transactions also involves the risk that counterparties, which generally are financial institutions, will be unable to perform their financial and other obligations under such transactions. If any of our counterparties were to default on its obligations to us under the derivative contracts, enter receivership or seek bankruptcy or similar protection, that could result in an economic loss to us and could have a material 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. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened, and it is possible that fewer counterparties will participate in future derivative transactions, which could result in greater concentration of our exposure to any one counterparty or a larger percentage of our future production being subject to commodity price changes.

Federal legislation regarding swaps could adversely affect the costs of, or our ability to enter into, those transactions. Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which was passed by Congress and signed into law in July 2010, amends the Commodity Exchange Act (CEA) to establish a comprehensive new regulatory framework for over-the-counter derivatives, or swaps, and swaps market participants, such as Newfield. The Dodd-Frank Act requires certain swaps to be cleared through a derivatives clearing organization, unless an exception from mandatory clearing is available, and if the swap is subject to a clearing requirement, to be executed on a designated contract market or swap execution facility, and that market participants post margin for uncleared swaps. The CEA provides that non-financial entity end-users, such as Newfield, that enter into swaps to hedge or mitigate commercial risk may elect an exception from the mandatory clearing and exchange trading requirements. However, unless an exemption from the Dodd-Frank Act's margin requirements is available, our derivative transactions could be subject to higher costs due to margin payments to swap counterparties. While we do not expect that we will be required to post margin for uncleared swaps, the Commodity Futures Trading Commission (CFTC) has not yet finalized the margin rules. Therefore, we are unable to determine the future costs on our derivative activities at this time.

Higher costs associated with the Dodd-Frank Act can create disincentives for end-users like Newfield to hedge their commercial risks, including market price fluctuations associated with anticipated production of oil and gas. The Dodd-Frank Act and related rules and regulations promulgated by CFTC could potentially increase the cost of Newfield's risk management activities, which could adversely affect our available liquidity, materially alter the terms of our swap contracts, reduce the availability of swaps to hedge or mitigate risks we encounter, reduce our ability to monetize or restructure existing swap contracts, and increase our regulatory compliance costs related to our swap activities. In addition, if we reduce our use of swaps, our results of operations and cash flows may be adversely affected, including by becoming more volatile and less predictable, which also could adversely affect our ability to plan for and fund capital expenditures. It is also possible that the Dodd-Frank Act and related rules and regulations could affect prices for commodities that we purchase, use or sell, which, in turn, could adversely affect our liquidity or financial condition.

In December 2013, the CFTC re-proposed rules to amend the CEA to establish position limits for certain commodity futures and options contracts, and physical commodity swaps that are economically equivalent to such contracts, including on commodity derivative transactions in which we engage in beyond certain thresholds. If the CFTC position limit regulations are ultimately adopted substantially in the form proposed, they could result in additional compliance costs and alter our ability to effectively manage our commercial risks. Until the CFTC adopts final rules with respect to position limits and any exemptions for bona fide derivative transactions or off-setting positions from those limits, we will be unable to determine whether the CFTC's proposed rules could result in additional derivative costs or adversely affect our ability to effectively manage our commercial risks.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on the leases or units containing the leasehold acreage. Leases on oil and gas properties normally have a term of three to five years and will expire unless, prior to expiration of the lease term, production in paying quantities is established. If the leases expire and we are unable to renew them, we will lose the right to develop the related properties. The risk of the foregoing increases in periods of sustained low commodity prices due to the corresponding impact on our drilling plans and the likely decrease in what is considered economic production under the leases. Our drilling plans for these areas are subject to change based upon various factors, including commodity prices, drilling results, 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.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation. In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, among other proposals:

•the repeal of the percentage depletion allowance for oil and gas properties;
•the elimination of current deductions for intangible drilling and development costs;

- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

These proposals were also included in the President of the United States' Proposed Fiscal Year 2014 Budget. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of such legislation or any other similar changes in U.S. Federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control. The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. We deliver oil and gas through gathering systems and pipelines that we do not own. The lack of available capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through some firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, or may not be available to us in the future at a price that is acceptable to us. New regulations on the transportation of crude oil by rail, like those issued via emergency orders by the U.S. Department of Transportation (DOT) in 2014, may increase our transportation costs. In addition, federal and state regulation of natural gas and oil production, processing and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints and general economic conditions could adversely affect our ability to produce, gather and transport natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

We have risks associated with our China operations. Ownership of property interests and production operations in China are subject to the various risks inherent in international operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, piracy, acts of terrorism, insurrection, civil unrest and other political risks or other changes in government;
- difficulties obtaining permits or governmental approvals as a foreign operator;
- increases in taxes and governmental royalties;
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act and other anti-corruption compliance laws and issues;
- disruptions in international crude oil cargo shipping activities;
- physical, digital, internal and external security breaches;
- forced renegotiation of, unilateral changes to, or termination of contracts with, governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations in China;
- our limited ability to influence or control the operation or future development of non-operated properties;
- the operator’s expertise or other labor problems;
- cultural differences;
- difficulties enforcing our rights against a governmental entity because of the doctrine of sovereign immunity and foreign sovereignty over our China operations; and
- other uncertainties arising out of foreign government sovereignty over our China operations.

Our China operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation, investment and transparency issues. In addition, if a dispute arises with respect to our China operations, we may be subject to the exclusive jurisdiction of non-U.S. courts or may not be successful in subjecting non-U.S. persons to the jurisdiction of the courts of the United States. Realization of any of the factors listed above could materially and adversely affect our financial position, results of operations or cash flows.

Material differences between the estimated and actual timing of critical events may affect the completion of and commencement of production from our Pearl development project in China. Our Pearl facility in the South China Sea is a large, offshore development project. The completion of our drilling in this project may be delayed beyond our anticipated completion dates. Key factors that may affect the timing and outcome of this project include the following:
•project approvals by our joint-venture partner(s);
•timely issuance of permits and licenses by governmental agencies or legislative and other governmental approvals;
•weather conditions;
•availability of personnel;
•civil and political environment in China; and
•manufacturing and delivery schedules of critical equipment.
Delays and differences between estimated and actual timing of critical events may affect the forward-looking statements related to our Pearl development and could have a material adverse effect on our expected timing and amount of cash flows from China and international results of operations.

Competition for, or the loss of, our senior management or experienced technical personnel may negatively impact our operations or financial results. To a large extent, we depend on the services of our senior management and technical personnel and the loss of any key personnel could have a material adverse effect on our business, financial condition and operating results. Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain a seasoned management team and experienced explorationists, engineers, geologists and other professionals. Competition for these professionals remains strong. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed. We are likely to continue to experience increased costs to attract and retain these professionals.

Competition in the oil and gas industry is intense. We operate in a highly competitive environment for acquiring properties and marketing oil, natural gas and NGLs. Our competitors include multinational oil and gas companies, major oil and gas companies, independent oil and gas companies, individual producers, financial buyers as well as participants in other industries supplying energy and fuel to consumers. Many of our competitors have greater and more diverse resources than we do. In addition, high commodity prices and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties. We compete for the personnel and equipment required to explore, develop and operate properties. Our competitors also may have established long-term strategic positions and relationships in areas in which we may seek new entry. As a consequence, our competitors may be able to address these competitive factors more effectively than we can. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

Shortages of oilfield equipment, services, supplies and qualified field personnel could adversely affect financial condition and results of operations. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for that equipment has increased along with the number of wells being drilled. The demand for qualified and experienced field personnel to drill wells and conduct field operations can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. These factors have caused significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment, services and raw materials. Similarly, lower crude oil and natural gas prices generally result in a decline in service costs due to reduced demand for drilling and completion services. If the current market changes, and commodity prices quickly recover, we may face shortages of field personnel, drilling rigs, or other equipment or supplies, which could delay or adversely affect our exploration and development operations and have a material adverse effect on our business, financial condition, results of operations or cash flows, or restrict operations.

Our ability to produce oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner. Development activities require the use of water. For example, the hydraulic fracturing process that we employ to produce commercial quantities of natural gas and oil from many reservoirs requires the use and disposal of significant quantities of water in addition to the water we use to develop our waterflood in the GMBU. In certain regions, there may be insufficient local capacity to provide a source of water for drilling activities. In these cases, water must be obtained from other sources and transported to the drilling site, adding to the operating cost. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations, such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of natural gas and oil. In recent history, public concern surrounding increased seismicity has heightened focus on our industry's use of water in operations, which may cause increased costs, regulations or environmental initiatives impacting our use or disposal of water.

We may not be insured against all of the operating risks to which our business is exposed. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, such as well blowouts, explosions, oil spills, releases of gas or well fluids, fires, pollution and adverse weather conditions, which could result in substantial losses to us. See also "- The oil and gas business involves many operating risks that can cause substantial losses." Exploration and production activities are also subject to risk from political developments such as terrorist acts, piracy, civil disturbances, war, expropriation or nationalization of assets, which can cause loss of or damage to our property. We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our insurance coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our onshore and offshore operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution and other environmental issues, with broader coverage for sudden and accidental occurrences. For example, we maintain operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operators extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims.

Further, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

We may be subject to risks in connection with acquisitions and divestitures. As part of our business strategy, we have made and will likely continue to make acquisitions of properties and to divest non-strategic assets. Suitable acquisition properties or suitable buyers of our non-strategic assets may not be available on terms and conditions we find acceptable.

Acquisitions pose substantial risks to our business, financial condition and results of operations. These risks include that the acquired properties may not produce revenues, reserves, earnings or cash flows at anticipated levels. Also, the integration of properties we acquire could be difficult. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire properties. The successful acquisition of producing properties requires an assessment of several factors, including:

•recoverable reserves;
•exploration potential;
•future oil and gas prices and their appropriate differentials;
•operating costs and production taxes; and
•potential environmental and other liabilities.

These assessments are complex and the accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

In addition, our divestitures may pose residual risks to the Company, such as divestitures where we retain certain liabilities or we have legal successor liability due to the bankruptcy or dissolution of the purchaser. Uneconomic or unsuccessful acquisitions and divestitures may divert management's attention and financial resources away from our existing operations, which could have a material adverse effect on our financial condition.

We depend on computer and telecommunications systems, and failures in our systems or cyber security attacks could significantly disrupt our business operations. The oil and gas industry has become increasingly dependent upon digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Our business partners, including vendors, service providers, purchasers of our production and financial institutions, are also dependent on digital technology. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any cyber incidents or interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could lead to data corruption, communication interruption, unauthorized release, gathering, monitoring, misuse or destruction of proprietary or other information, or otherwise significantly disrupt our business operations. As cyber threats 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 information security vulnerabilities.

We are exposed to counterparty credit risk as a result of our receivables. We are exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of our purchasers and non-operating partners may experience credit downgrades or liquidity problems and may not be able to meet their financial obligations to us. Nonperformance by a trade creditor or non-operating partner could result in financial losses.

Hurricanes, typhoons, tornadoes, earthquakes and other natural disasters could have a material adverse effect on our business, financial condition, results of operations and cash flow. Hurricanes, typhoons, tornadoes, earthquakes and other natural disasters can potentially destroy thousands of business structures and homes and, if occurring in the Gulf Coast region of the United States, could disrupt the supply chain for oil and gas products. Disruptions in supply could have a material adverse effect on our business, financial condition, results of operations and cash flow. Damages and higher prices caused by hurricanes, typhoons, tornadoes, earthquakes and other natural disasters could also have an adverse effect on our financial condition due to the impact on the financial condition of our customers.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.   We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales, and near-term and long-term production growth opportunities. Liquidity, asset quality, cost structure, product mix, and commodity pricing levels are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt, and potentially require us to post letters of credit or other forms of collateral for certain obligations.

Our level of indebtedness and the restrictive covenants in the agreements governing our indebtedness and other financial obligations may reduce our operating flexibility. As of December 31, 2014, we had total indebtedness of $2.9 billion, including $0.4 billion in borrowings under our revolving credit facility and money market lines of credit. The indenture governing our outstanding notes and the agreements governing our other indebtedness and financial obligations contain, and any indenture that will govern other debt securities issued by us may contain, various covenants that limit our ability and the ability of specified subsidiaries of ours to, among other things:

- incur additional indebtedness;
- purchase or redeem our outstanding equity interests or subordinated debt;
- make specified investments;
- create liens;
- sell assets;
- engage in specified transactions with affiliates;
- engage in sale-leaseback transactions; and
- effect a merger or consolidation with or into other companies or a sale of all or substantially all of our properties or assets.

These restrictions and our level of indebtedness could limit our ability to:

- obtain future financing;
- make needed capital expenditures;
- plan for, or react to, changes in our business and the industry in which we operate;
- compete with similar companies that have less debt;
- withstand a future downturn in our business or the economy in general; or
- conduct operations or otherwise take advantage of business opportunities that may arise.

Some of the agreements governing our indebtedness and other financial obligations also require the maintenance of specified financial ratios and the satisfaction of other financial conditions. Our ability to meet those financial ratios and conditions, and to comply with other covenants and restrictions in our financing agreements, can be affected by unexpected downturns in business operations beyond our control, such as a volatile energy commodity cost environment or an economic downturn. Accordingly, we may be unable to meet these obligations. This failure could impair our operating capacity and cash flows and could restrict our ability to incur debt or to make cash distributions, even if sufficient funds were available.

Our breach of any of these covenants could result in a default under the terms of the relevant indebtedness, which could cause such indebtedness or other financial obligations to become immediately due and payable. If the lenders accelerate the repayment of borrowings or other amounts owed, we may not have sufficient assets to repay our indebtedness or other financial obligations, including our outstanding notes and any future debt securities. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds from a sale of assets or a public offering of securities. Factors that will affect our ability to successfully complete a public offering, refinance our debt or conduct an asset sale include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations.

Our certificate of incorporation, bylaws, some of our arrangements with employees and Delaware law contain provisions that could discourage an acquisition or change of control of our Company. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to affect a change of control of our Company, to acquire us or to replace incumbent management. In addition, our change of control severance plan and agreements and our omnibus stock plans contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of restricted stock, restricted stock units and stock options, upon a change of control. Section 203 of the Delaware General Corporation Law also imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions could discourage or prevent a change of control, even if it may be beneficial to our stockholders, or could reduce the price our stockholders receive in an acquisition of our Company.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

Between February and December 2013, we voluntarily self-disclosed to the U.S. Environmental Protection Agency (EPA) certain potential federal air quality violations at our facilities located on state lands and on the Uintah and Ouray Indian Reservation in the Uinta Basin of northeast Utah. The self-disclosures were made after a voluntary internal environmental audit under the EPA's Self-Disclosure and Audit Policy. The potential violations related primarily to certain stationary internal combustion engines that are subject to certain air quality performance standards under 40 C.F.R. Part 60, Subpart JJJJ. The engines were installed as a result of our efforts to replace older, higher-emitting engines with new, lower-emitting engines. Subpart JJJJ requires us to conduct certain emission performance tests within a defined time period. We did not conduct all of the requisite tests on the new engines in a timely fashion and have now negotiated a settlement and resolution with the EPA by entering in to a Combined Complaint and Consent Agreement and Compliance Order on Consent. Those settlement documents require us to pay a monetary penalty of $246,000 and conduct testing for numerous engines. The settlement documentation was finalized on October 20, 2014 and the penalty was paid timely on November 7, 2014. The required performance testing is ongoing and we anticipate that work to be completed in a timely manner, consistent with the requirements of the settlement. The violations did not contain any allegations of environmental spills, releases or pollution above permitted levels. We do not expect this matter to have a material adverse effect on our financial position, cash flows or results of operations.

In early 2012, through a voluntary environmental audit, we discovered potential violations of section 404 of the Clean Water Act relating to possible unpermitted discharges of fill materials into certain wetlands and drainages in the Uinta Basin. The potential violations were discovered on certain Newfield locations and several locations acquired in 2011. In June 2012, we self-disclosed these potential violations to the U.S. Army Corps of Engineers (Corps), in accordance with the EPA’s Audit Policy and an interagency memorandum of understanding with the Corps. The Corps initially indicated to us that it would not pursue penalty charges, but instead would work with us to restore the unpermitted discharges and acquire the appropriate after-the-fact permits. The EPA later inquired with the Corps, and was informed about the potential violations. Thereafter, the EPA initiated an administrative enforcement action against Newfield. The EPA has evaluated the discharges and our proposed restoration and mitigation, and a negotiated settlement has been finalized. On November 13, 2014, Newfield entered into an Administrative Order on Consent and a Combined Complaint and Consent Agreement to settle the matter. The EPA executed both agreements on December 17, 2014. The EPA published the notice of the Combined Complaint and Consent Agreement on December 17, 2014, for a 40-day comment period. No comments were received by the EPA. The settlement terms involved payment of a $175,000 penalty, restoration of much of the unpermitted discharges and off-site mitigation. The EPA issued the Final Order together with the fully executed Combined Complaint and Consent Agreement on January 27, 2015. The penalty will be paid before February 27, 2015 and the remediation and mitigation work will begin in 2015. We do not expect this administrative settlement to have a material adverse effect on our financial position, cash flows or results of operations.

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations. In addition, from time to time we receive notices of violation from governmental and regulatory authorities in areas in which we operate related to alleged violations of environmental statutes or rules and regulations promulgated thereunder. We cannot predict with certainty whether these notices of violation will result in fines or penalties, or if such fines or penalties are imposed, that they would individually or in the aggregate exceed $100,000. If any fines or penalties are in fact imposed that are greater than $100,000, then we will disclose such fact in our subsequent filings.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

The following table sets forth the names, ages (as of February 20, 2015) and positions held by our executive officers. Our executive officers serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
Lee K. Boothby	53	President, Chief Executive Officer and Chairman of the Board	15
Lawrence S. Massaro	51	Executive Vice President and Chief Financial Officer	4
Gary D. Packer	52	Executive Vice President and Chief Operating Officer	19
George T. Dunn	57	Senior Vice President — Development	22
John H. Jasek	45	Senior Vice President — Operations	15
Stephen C. Campbell	46	Vice President — Investor Relations	15
George W. Fairchild, Jr.	47	Chief Accounting Officer and Assistant Corporate Secretary	3
John D. Marziotti	51	General Counsel and Corporate Secretary	11
Valerie A. Mitchell	43	Vice President — Mid-Continent	10
Matthew R. Vezza	41	Vice President — Rocky Mountains	2

Lee K. Boothby was named Chairman of the Board of Directors in May 2010, Chief Executive Officer in May 2009 and President in February 2009. Prior to this, he was Senior Vice President — Acquisitions and Business Development. From 2002 to 2007, he was Vice President — Mid-Continent. From 1999 to 2001, Mr. Boothby was Vice President and Managing Director — Newfield Exploration Australia Ltd. and managed operations in the Timor Sea (divested in 2003) from Perth, Australia. Prior to joining Newfield in 1999, Mr. Boothby worked for Cockrell Oil Corporation, British Gas and Tenneco Oil Company. He serves as a board member for America's Natural Gas Alliance and the American Exploration and Production Council. He is a member of the Louisiana State University Craft & Hawkins Department of Petroleum Engineering Advisory Committee, the Society of Petroleum Engineers, the Independent Petroleum Association of America and the Rice University Jones Graduate School of Business Council of Overseers. He holds a degree in Petroleum Engineering from Louisiana State University and a Master of Business Administration from Rice University.

Lawrence S. Massaro was promoted to Executive Vice President and Chief Financial Officer in November 2013. Mr. Massaro joined Newfield in March 2011 and served as Vice President — Corporate Development until November 2013. In this position, he led the Company's business development, strategic planning and product marketing efforts. Prior to joining Newfield, Mr. Massaro served as Managing Director at JP Morgan in its oil and gas investment banking group beginning in 2005 and was Vice President, Corporate Strategy and Business Development while at Amerada Hess Corporation from 1995 to 2005. He also held various senior petroleum engineering positions at both PG&E Resources from 1992 to 1994 and at British Petroleum from 1985 to 1991. Mr. Massaro holds a degree in Petroleum Engineering from Texas A&M University and a Master of Business Administration from Southern Methodist University.

Gary D. Packer was promoted to the position of Executive Vice President and Chief Operating Officer in May 2009. Prior thereto, he was promoted from Gulf of Mexico General Manager to Vice President — Rocky Mountains in November 2004. Mr. Packer joined the Company in 1995. Prior to joining Newfield, Mr. Packer worked for Amerada Hess Corporation in both the Rocky Mountains and Gulf of Mexico divisions. Prior to these roles, he worked for Tenneco Oil Company. In December 2014, Mr. Packer joined the board of directors of Bennu Oil & Gas, LLC, a private oil and gas company operating offshore in the Gulf of Mexico. He serves as a board member for the Independent Petroleum Association of America (IPAA). He holds a degree in Petroleum and Natural Gas Engineering from Penn State University.

George T. Dunn was promoted to Senior Vice President — Development in September 2012, previously serving as Vice President — Mid-Continent beginning in October 2007. He managed our onshore Gulf Coast operations from 2001 to October 2007, and was promoted from General Manager to Vice President in November 2004. Before managing our Gulf Coast operations, Mr. Dunn was the General Manager of our Western Gulf of Mexico division. Prior to joining Newfield in 1992, Mr. Dunn was employed by Meridian Oil Company and Tenneco Oil Company. He holds a degree in Petroleum Engineering from the Colorado School of Mines.

John H. Jasek was promoted to Senior Vice President — Operations in October of 2014, after serving as Vice President — Onshore Gulf Coast since February 2011. Prior to that, Mr. Jasek served as Vice President — Gulf of Mexico from December 2008 until February 2011 and as Vice President — Gulf Coast from October 2007 until December 2008 while also serving as the manager of our onshore Gulf Coast operations. He previously managed our Gulf of Mexico operations from March 2005 until October 2007, and was promoted from General Manager to Vice President in November 2006. Prior to March 2005, he was a Petroleum Engineer in the Western Gulf of Mexico. Before joining Newfield, Mr. Jasek worked for Anadarko Petroleum Corporation and Amoco Production Company. He has a degree in Petroleum Engineering from Texas A&M University.

Stephen C. Campbell was promoted to Vice President — Investor Relations in December 2005, after serving as Newfield's Manager — Investor Relations since 1999. Prior to joining Newfield, Mr. Campbell was the Investor Relations Manager at Anadarko Petroleum Corporation from 1993 to 1999 and the Assistant Vice President of Marketing & Communications at United Way, Texas Gulf Coast from 1990 to 1993. He is a member of the National Investor Relations Institute. He holds a Bachelor of Science degree in Journalism from Texas A&M University.

George W. Fairchild, Jr. was promoted to Chief Accounting Officer and Assistant Corporate Secretary in November 2013. Mr. Fairchild joined Newfield in August of 2012 as Controller and Assistant Corporate Secretary and has served as the Company's Principal Accounting Officer since joining the Company. Prior to joining Newfield, Mr. Fairchild served as Controller for Sheridan Production Company LLC, a privately-held oil and gas company, beginning in 2009 and was Vice President and Controller of Davis Petroleum Corporation, also a privately-held oil and gas company, from 2006 to 2009. Prior thereto, Mr. Fairchild was with Burlington Resources Inc., a publicly-held oil and gas company, serving as Senior Manager — Accounting Policy & Research from 2001 to 2006 and Manager — Internal Audit from 2000 to 2001. Before joining Burlington Resources Inc., he was with PricewaterhouseCoopers LLP from 1993 to 2000. Mr. Fairchild served in the U.S. Air Force from 1986 to 1990. He holds a Bachelor of Business Administration in Accounting from the University of Texas at Austin and is a Certified Public Accountant in the state of Texas.

John D. Marziotti was promoted to General Counsel in August 2007 and was named Corporate Secretary in May 2008. Prior to joining Newfield in 2003, Mr. Marziotti was a partner at the law firm of Strasburger & Price, LLP in their Houston office. He received his Juris Doctor degree from Southern Methodist University and a Bachelor of Arts degree from the College of Charleston and is a member of the State Bar of Texas, the Houston Bar Association, the Association of Corporate Counsel, Texas General Counsel Forum and is a Board Leadership Fellow with the National Association of Corporate Directors.

Valerie A. Mitchell was promoted to Vice President — Mid-Continent effective February 9, 2015, after serving as Vice President — Corporate Development beginning in June of 2014. From 2011 to June 2014, she served as General Manager of our Mid-Continent business unit. Prior to that, Ms. Mitchell served in a number of leadership roles since joining Newfield in July 2004, including business development manager for our onshore Gulf Coast region and asset lead and asset manager from 2009 to 2011. Ms. Mitchell began her career as a reservoir engineer with Shell Oil in 1996 and thereafter worked in various technical and management positions at Coastal and El Paso. She has served in leadership positions for several industry organizations including the Oklahoma Independent Producers Association and the Society of Petroleum Engineers. She holds a Bachelor of Science in Chemical Engineering from the University of Missouri-Columbia.

Matthew R. Vezza was promoted to Vice President — Rocky Mountains in June of 2014. Mr. Vezza joined Newfield in August 2012 as General Manager of our Rocky Mountains business unit after 16 years with Marathon Oil Company. Mr. Vezza began his career at Marathon in 1996 as a production engineer and then moved through the organization in various technical and managerial roles in Oklahoma, Texas, Louisiana, Colorado and Wyoming. While at Marathon, Mr. Vezza's last position, from August 2009 to August 2012, was serving as Asset Manager - Wyoming. Mr. Vezza is a member of the Society of Petroleum Engineers and holds a Bachelor of Science in Petroleum and Natural Gas Engineering from Penn State University.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for Common Stock

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol “NFX.” The following table sets forth, for each of the periods indicated, the high and low reported sales price of our common stock on the NYSE.

	High	Low
2013:		
First Quarter	$30.50	$22.14
Second Quarter	25.73	19.57
Third Quarter	28.41	22.71
Fourth Quarter	32.55	22.79
2014:		
First Quarter	$31.75	$23.57
Second Quarter	44.26	30.94
Third Quarter	45.43	36.97
Fourth Quarter	37.49	22.90
2015:		
First Quarter (through February 20, 2015)	$33.46	$22.31

On February 20, 2015, the last reported sales price of our common stock on the NYSE was $32.09. As of that date, there were approximately 1,526 holders of our common stock.

Dividends

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indentures governing our 6 % Senior Subordinated Notes due 2020, our 5¾% Senior Notes due 2022 and our 5 % Senior Notes due 2024 could restrict our ability to pay cash dividends. See “Contractual Obligations” under Item 7 of this report and Note 9, “Debt,” to our consolidated financial statements in Item 8 of this report.

Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2014.

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased under the Plans or Programs
October 1 — October 31, 2014	7,763	$36.81	—	—
November 1 — November 30, 2014	6,650	31.69	—	—
December 1 — December 31, 2014	3,672	25.53	—	—
Total	18,085	$32.64	—	—

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards and restricted stock units. These repurchases were not part of a publicly announced program to repurchase shares of our common stock.

Stockholder Return Performance Presentation

The performance presentation below is being furnished pursuant to applicable rules of the SEC. As required by these rules, the performance graph was prepared based upon the following assumptions:

- $100 was invested in our common stock, the S&P 500 Index, the Philadelphia Oil/Exploration & Production Index (EPX) and our peer group on December 31, 2009 at the closing price on such date;
- investment in our peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of the period; and
- dividends were reinvested on the relevant payment dates.

For 2015, we refreshed our peer group to better reflect our focus on U.S. domestic resource plays.

New Peer Group. Our new peer group consists of Cimarex Energy Co., Continental Resources Inc., EP Energy Corp., QEP Resources Inc., SandRidge Energy Inc., SM Energy Company and Whiting Petroleum Corporation.

Prior Peer Group. Our prior peer group consisted of Bill Barrett Corp., Carrizo Oil & Gas Inc., EP Energy Corp., Halcon Resources Corp., QEP Resources Inc., Rosetta Resources Inc., SandRidge Energy Inc. and SM Energy Company.

Comparison of Five-Year Cumulative Total Return

Total Return Analysis	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014
Newfield Exploration Company	$ 100.00	$ 149.51	$ 78.23	$ 55.53	$ 51.07	$ 56.23
S&P 500 Index - Total Returns	100.00	115.06	117.49	136.30	180.44	205.14
PHLX SIG Oil Exploration & Production Index	100.00	123.12	111.96	104.20	131.89	94.56
New Peer Group	100.00	147.15	138.23	132.96	190.89	128.28
Prior Peer Group	100.00	136.36	134.81	113.98	131.47	69.96

Item 6. Selected Financial Data

SELECTED FIVE-YEAR FINANCIAL DATA

The following table shows selected consolidated financial data derived from our consolidated financial statements set forth in Item 8 of this report. The data should be read in conjunction with Items 1 and 2, “Business and Properties,” and Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” of this report.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions, except per share data)				
Statement of Operations Data:					
Oil, gas and NGL revenues[1]	$2,288	$1,857	$1,562	$1,824	$1,484
Income (loss) from continuing operations	650	73	(922)	427	429
Net income (loss)	900	147	(1,184)	539	523
Earnings (loss) per share:					
Diluted:					
Income (loss) from continuing operations	$4.71	$0.39	$(6.85)	$3.16	$3.20
Diluted earnings (loss) per share	6.52	0.94	(8.80)	3.99	3.91
Weighted-average number of shares outstanding for diluted earnings (loss) per share	138	136	135	135	134
Balance Sheet Data (at end of period):					
Total assets	$9,598	$9,321	$7,912	$8,991	$7,494
Long-term debt	2,892	3,694	3,045	3,006	2,304

(1) Continuing operations only (excludes Malaysia).

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

Overview

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our principal areas of operation include the Mid-Continent, Rocky Mountains and onshore Gulf Coast regions of the United States. Internationally, we have offshore oil developments in China.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and locate or acquire new oil and natural gas reserves to replace those reserves being produced. Our revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on our ability to find, develop and acquire oil and natural gas reserves that are economically recoverable. Prices for oil, natural gas and NGLs fluctuate widely and affect:

- the amount of cash flows available for capital expenditures;
- our ability to borrow and raise additional capital; and
- the quantity of oil, natural gas and NGLs that we can economically produce.

Crude oil and natural gas prices decreased significantly during the fourth quarter of 2014 and have remained low into the first quarter of 2015. Nevertheless, we had many operational, financial and strategic successes in 2014. As a result, we believe we are better positioned to face the challenges of 2015.

Significant 2014 highlights include:

- domestic production increased 20% over 2013 to 46.4 MMBOE, excluding approximately 8.5 Bcf of natural gas produced and consumed in operations;
- domestic liquids production up 38% over 2013;
- best in class well in each region: Uinta, Anadarko and Williston Basins;
- net acres in the Anadarko Basin increased to nearly 300,000;
- our Pearl development in China achieved first oil and commenced production in the fourth quarter;

- income from operations increased $125 million over 2013 to $575 million;
- lease operating expense for continuing operations, on a per BOE basis, decreased 5% year-over-year;
- general and administrative expense for continuing operations, on a per BOE basis, decreased 15% year-over-year;
- net derivative asset of $613 million recognized, $423 million of which is current;
- sold our Granite Wash assets for $588 million and used proceeds from the sale to redeem our 2018 Senior Subordinated Notes of $600 million;
- sold our Malaysia business for $898 million and used the proceeds from the sale to fund 2014 capital expenditures;
- reduced debt and strengthened our balance sheet through divestitures; and
- released inaugural Corporate Responsibility Report.

Building on the results of 2014, we have adapted our 2015 business plan to focus on the following goals in response to this period of dramatic oil and natural gas price declines:

- maintain and prioritize liquidity preservation over reserve and production growth;
- match capital investments with cash flows from operations;

- allocate the majority of capital to the Anadarko Basin of Oklahoma;
- implement a plan to reduce gross general and administrative expenses by 10% to 15%; and
- implement a plan to reduce domestic per unit lease operating costs by approximately 5 to 15%.

While we expect to achieve savings from cost reductions during 2015, given the lower oil and natural gas price environment as compared to 2014, our revenues and operating income are expected to be lower in 2015 as compared to 2014.

Discontinued Operations

During the second quarter of 2013, our businesses in Malaysia and China met the criteria to be classified as held for sale and reported as discontinued operations. In February 2014, Newfield International Holdings Inc., a wholly-owned subsidiary of the Company, closed the sale of our Malaysia business to SapuraKencana Petroleum Berhad, a Malaysian public company, for $898 million. See Note 1, "Organization and Summary of Significant Accounting Policies," and Note 3, "Discontinued Operations," to our consolidated financial statements in Item 8 of this report for additional information regarding the sale of our Malaysia business. During 2014, we continued to market our China business with bids due December 2014. Due to the precipitous decline in oil prices in the fourth quarter, we were unable to sell our China business at an acceptable price and determined it was in the Company's best interest to retain the cash flow from the China business. Accordingly, we reclassified this business as continuing operations for all periods presented.

Results of Continuing Operations

Our continuing operations consist of exploration, development and production activities in the United States and China. The production and average realized prices tables below include our Gulf of Mexico operations for 2012. In the 2012 discussion below, we excluded revenue of $116 million and production of 2,369 MBOE related to our Gulf of Mexico assets that were fully divested in the fourth quarter of 2012 in order to provide a more comparable analysis of our continuing operations.

Domestic Revenues. Revenues from domestic operations of $2.2 billion for the year ended December 31, 2014 were 26% higher than 2013. The increase was primarily due to a 38% year-over-year increase in our liquids production. Increased oil production generated approximately 81% of the total revenue increase due to production increases in our Mid-Continent, onshore Gulf Coast and Rocky Mountains regions of 51%, 26% and 26%, respectively. The increase related to higher oil production was partially offset by lower oil prices, which reduced the overall oil volume and price impact to 58% of the total revenue growth. Increased NGL production in the Mid-Continent, onshore Gulf Coast and Rocky Mountains regions of 67%, 44% and 35%, respectively, during the year ended December 31, 2014 generated approximately 20% of the total revenue increase. Approximately 18% of the total revenue increase was due to higher natural gas prices received during the year ended December 31, 2014 compared to the year ended December 31, 2013.

Revenues from domestic operations of $1.8 billion for the year ended December 31, 2013 were 32% higher than 2012. The increase was primarily due to higher liquids production and commodity prices in 2013. Our liquids production increased 43% year-over-year. As expected, our natural gas production declined as we continued to focus capital investments on higher-margin liquids production. Approximately 58% of the revenue increase in 2013 was attributable to increases in oil production in our Mid-Continent, onshore Gulf Coast and Rocky Mountains regions of 47%, 59% and 18%, respectively. Higher realized oil prices also increased revenues along with this favorable volume variance. Additionally, revenues increased 21% due to year-over-year NGL production increases in the Mid-Continent, onshore Gulf Coast and Rocky Mountains regions of 180%, 59% and 23%, respectively, partially offset by lower NGL prices. While natural gas production declined 14% in 2013, a 29% increase in the realized price during the period more than offset the negative production impact on revenue.

China Revenues. Our China revenues are recorded when oil is lifted and sold, not when it is produced into floating storage facilities. As a result, the timing of liftings may impact period-to-period results.

Revenues from China of $39 million for the year ended December 31, 2014 were 43% lower than 2013. The decrease was primarily due to the temporary shut-in of production in Bohai Bay by the operator during the second and third quarters of 2014 for scheduled repair and maintenance activities, along with a 24% decrease in oil price during 2014. Revenues from China of $69 million for the year ended December 31, 2013 were 20% lower than 2012. The decrease was primarily due to 18% lower production and slightly lower commodity prices.

The following table reflects our production from continuing operations and average realized commodity prices:

	2014	2013	2012
Production/Liftings:			
Domestic:(1)			
Crude oil and condensate (MBbls)	18,547	14,200	11,988
Natural gas (Bcf)	118.2	116.1	143.5
NGLs (MBbls)	8,207	5,163	2,608
Total (MBOE)	46,448	38,706	38,521
China:(2)			
Crude oil and condensate (MBbls)	499	668	811
Total continuing operations:			
Crude oil and condensate (MBbls)	19,046	14,868	12,799
Natural gas (Bcf)	118.2	116.1	143.5
NGLs (MBbls)	8,207	5,163	2,608
Total (MBOE)	46,946	39,374	39,332
Average Realized Prices:			
Domestic:(3)			
Crude oil and condensate (per Bbl)	$80.40	$86.21	$83.99
Natural gas (per Mcf)	4.11	3.39	2.64
NGLs (per Bbl)	32.04	30.74	31.26
Crude oil equivalent (per BOE)	48.41	45.91	38.10
China:			
Crude oil and condensate (per Bbl)	$78.52	$103.19	$106.53
Total continuing operations:			
Crude oil and condensate (per Bbl)	$80.35	$86.97	$85.42
Natural gas (per Mcf)	4.11	3.39	2.64
NGLs (per Bbl)	32.04	30.74	31.26
Crude oil equivalent (per BOE)	48.73	46.88	39.51

(1) Excludes natural gas produced and consumed in operations of 8.5 Bcf in 2014, 8.1 Bcf in 2013 and 7.8 Bcf in 2012.

(2) Represents our net share of volumes sold regardless of when produced.

(3) We had no outstanding derivative contracts related to our NGL production or our production associated with our international operations. Had we included the realized effects of derivative contracts, the domestic average realized prices would have been as follows:

	2014	2013	2012
Crude oil and condensate (per Bbl)	$80.23	$85.77	$84.10
Natural gas (per Mcf)	3.81	3.97	3.57

Domestic Production. For the year ended December 31, 2014, production from domestic operations increased 20% primarily due to increased liquids production. Our total 2014 domestic liquids production increased 38% over the prior year due to the success of our liquids-focused drilling programs. Almost 60% of the increase in total liquids was attributable to higher margin crude oil. Natural gas production increased 2% due to associated gas production generated by our liquids-focused drilling programs.

For the year ended December 31, 2013, production from domestic operations increased 7% over the prior year. Crude oil and NGL production increased 43% in 2013 but was partially offset by decreases in natural gas production across our domestic regions. The decrease in natural gas production was due to natural decline as a result of reduced investment in natural gas wells. More than half of the increase in total liquids in 2013 was attributable to higher margin crude oil.

China Production/Liftings. For the year ended December 31, 2014, production from China decreased 25% compared to the same period in 2013 primarily due to the temporary shut-in of production in Bohai Bay by the operator between May and

August 2014 for scheduled repairs and maintenance activities. Production resumed in August 2014; however, we had not accumulated sufficient quantities to schedule a lifting during the remainder of the year. Liftings from Bohai Bay are expected to resume in the first quarter of 2015. The decrease in liftings from Bohai Bay was partially offset by the first lifting from our Pearl development in December 2014. Our Pearl development achieved first oil in the fourth quarter of 2014 after the repaired LF-7 topside facilities were installed in August 2014.

For the year ended December 31, 2013, production from China decreased 18% compared to the same period in 2012 due to natural production decline combined with no wells drilled in the last nine months of the year.

Operating Expenses.

Year ended December 31, 2014 compared to December 31, 2013

The following table presents information about operating expenses for our continuing operations:

	Unit-of-Production Year Ended December 31,		Percentage Increase (Decrease)	Total Amount Year Ended December 31,		Percentage Increase (Decrease)
	2014	2013		2014	2013	
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$6.64	$7.13	(7)%	$309	$276	12%
Transportation and processing	3.74	3.54	6%	174	137	27%
Production and other taxes	2.26	1.73	31%	105	67	57%
Depreciation, depletion and amortization	18.46	17.25	7%	857	668	28%
General and administrative	4.78	5.67	(16)%	221	219	1%
Other	0.32	0.07	357%	15	3	489%
Total operating expenses	36.21	35.38	2%	1,681	1,370	23%
China:						
Lease operating	$24.05	$11.99	101%	$12	$8	51%
Production and other taxes	11.20	17.82	(37)%	6	12	(53)%
Depreciation, depletion and amortization	25.87	26.47	(2)%	13	17	(27)%
General and administrative	1.11	—	100%	1	—	100%
Total operating expenses	62.23	56.28	11%	32	37	(17)%
Total Continuing Operations:						
Lease operating	$6.83	$7.20	(5)%	$321	$284	13%
Transportation and processing	3.70	3.48	6%	174	137	27%
Production and other taxes	2.36	2.00	18%	111	79	40%
Depreciation, depletion and amortization	18.53	17.41	6%	870	685	27%
General and administrative	4.74	5.57	(15)%	222	219	2%
Other	0.32	0.06	433%	15	3	489%
Total operating expenses	36.48	35.73	2%	1,713	1,407	22%

Domestic Operations. For the year ended December 31, 2014, total operating expenses per BOE for domestic operations increased 2% as compared to the year ended December 31, 2013. The primary reasons for the change follow:

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Lease operating expenses decreased 7% on a per BOE basis. Higher production volumes, coupled with flat year-over-year well repair costs in all areas, generated approximately 60% of the per BOE reduction. The remaining decrease relates primarily to successful water and compression cost management initiatives in our Williston Basin, Mid-Continent and onshore Gulf Coast areas.

- Transportation and processing expense increased 6% on a per BOE basis primarily due to a 59% increase in NGL volumes processed during 2014.
- Production and other taxes as a percent of revenue increased 1%. Approximately one-half of this increase is the result of higher tax incentives as well as an ad valorem tax true-up in 2013. The remaining increase, on a percent of revenue basis, is primarily due to the significant growth of our Williston Basin production, which is subject to a higher production tax rate. On a per BOE basis, the increase is driven by increased liquids production as a percent of total production, and the associated increase in average revenue per BOE produced from $45.91 for the year ended December 31, 2013 to $48.41 for the year ended December 31, 2014.
- Total depreciation, depletion and amortization (DD&A) increased 28% primarily due to the 20% increase in production volumes in 2014 compared to 2013, combined with a 7% increase in the cost per unit of production. The increased cost per unit of production is primarily due to the transfer of approximately $760 million of unevaluated property costs into the full cost pool amortization base during the year. The majority of the costs were transferred in the fourth quarter in response to the significant decrease in oil and natural gas prices and the resulting impact on our future development plans.
- General and administrative (G&A) expense on a per BOE basis decreased 16% primarily due to increased production in 2014 as compared to 2013. G&A expense was flat year-over-year as increased employee-related expenses in 2014 were offset by higher capitalization of direct internal costs. Employee-related expenses increased by $32 million for stock-based compensation, primarily due to our Stockholder Value Appreciation Program, which achieved three payout targets in 2014 compared to one in 2013 (see Note 11, "Stock-based Compensation," to our consolidated financial statements in Item 8 of this report). The increase in stock-based compensation expense was partially offset by a decrease of $13 million in labor-related costs associated primarily with the centralization of certain functions during the second half of 2013. For the year ended December 31, 2014, we capitalized $135 million ($2.90 per BOE) of direct internal costs as compared to $107 million ($2.77 per BOE) during the comparable period of 2013. This increase is primarily due to a higher portion of the costs associated with stock-based liability awards earned by employees who are directly involved with our exploration and development activities.
- Other operating expense increased $12 million primarily due to equipment inventory value impairments and legal settlements during 2014 as compared to 2013.

China Operations. For the year ended December 31, 2014, total operating expenses per BOE for our China operations increased 11% compared to the year ended December 31, 2013. Results for 2014 include activity from Bohai Bay and our Pearl development, whereas 2013 results include only Bohai Bay.

LOE per barrel increased over 100% as a result of one-time production preparation costs associated with our Pearl development, a higher tariff on crude oil produced from our Pearl development and higher operating costs associated with deep water operations for Pearl. These increases were partially offset by a 37% decrease in production and other taxes per BOE, primarily due to the timing of liftings in China. Approximately 60% of our liftings in China were in the fourth quarter of 2014, which had significantly lower realized prices than 2013.

We expect that 2015 revenues and expenses in China will increase over 2014 as we execute our Pearl development plan. In January 2015, we completed one well, and we plan to drill 4 additional wells during the year. The Pearl development is expected to reach peak production by mid-2015.

Year ended December 31, 2013 compared to December 31, 2012

The following table presents information about our operating expenses for our continuing operations:

	Unit-of-Production Year Ended December 31,		Percentage Increase (Decrease)	Total Amount Year Ended December 31,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$7.13	$7.75	(8)%	$276	$299	(8)%
Transportation and processing	3.54	2.78	27%	137	107	28%
Production and other taxes	1.73	1.74	(1)%	67	67	—%
Depreciation, depletion and amortization	17.25	17.74	(3)%	668	683	(2)%
General and administrative	5.67	5.48	3%	219	211	4%
Ceiling test impairment	—	38.63	(100)%	—	1,488	(100)%
Other	0.07	0.38	(82)%	3	15	(83)%
Total operating expenses	35.38	74.50	(53)%	1,370	2,870	(52)%
China:						
Lease operating	$11.99	$8.95	34%	$8	$7	10%
Production and other taxes	17.82	22.49	(21)%	12	18	(35)%
Depreciation, depletion and amortization	26.47	26.20	1%	17	21	(17)%
Total operating expenses	56.28	57.64	(2)%	37	46	(20)%
Total Continuing Operations:						
Lease operating	$7.20	$7.77	(7)%	$284	$306	(7)%
Transportation and processing	3.48	2.72	28%	137	107	28%
Production and other taxes	2.00	2.17	(8)%	79	85	(8)%
Depreciation, depletion and amortization	17.41	17.91	(3)%	685	704	(3)%
General and administrative	5.57	5.36	4%	219	211	4%
Ceiling test impairment	—	37.84	(100)%	—	1,488	(100)%
Other	0.06	0.37	(84)%	3	15	(83)%
Total operating expenses	35.73	74.15	(52)%	1,407	2,916	(52)%

Domestic Operations. For the year ended December 31, 2013, total operating expenses for domestic operations increased 7% but were flat on a per BOE basis after adjusting for the 2012 ceiling test writedown and operating expenses of $102 million attributable to Gulf of Mexico assets that were fully divested in the fourth quarter of 2012. The components of significant period-to-period change for operating expenses excluding Gulf of Mexico related expenses related to 2012 are as follows:

- Lease operating expense decreased 2% on a per BOE basis primarily due to lower well repair costs in our Williston Basin, Mid-Continent and onshore Gulf Coast areas.
- Transportation and processing expense increased 22% on a per BOE basis primarily due to increased NGL volumes as a percent of total production resulting from our liquids-focused drilling program.
- Production and other taxes were flat on an actual cost and per unit basis. However, on a percent of revenue basis, they fell approximately 1%. This rate reduction is primarily attributable to production tax credits received in the Mid-Continent, onshore Gulf Coast and Uinta basins plus an $8 million adjustment of ad valorem taxes in the Uinta Basin previously expensed in 2012 and prior years. Without the ad valorem tax adjustment in the Uinta Basin,

production and other taxes on a percent of revenue basis would have decreased by less than a half of a percent.

- General and administrative expense increased during 2013 primarily due to employee-related expenses associated with our Voluntary Severance Program and Stockholder Value Appreciation Program (see Note 11, "Stock-Based Compensation," to our consolidated financial statements in Item 8 of this report), partially offset by the cost savings generated by the centralization of several administrative functions. During 2013, we capitalized $107 million ($2.77 per BOE) of direct internal costs as compared to $95 million ($2.45 per BOE) during 2012.
- In the fourth quarter of 2012, we recorded a ceiling test writedown of $1.5 billion due to a net decrease in the discounted value of our proved reserves. The primary reason for the change in value was negative price-related reserve revisions as a result of a 33% decrease in the natural gas SEC pricing.
- Other expenses in 2012 of $15 million included a writedown of $8 million of subsea wellhead inventory that was not included in the sale of our Gulf of Mexico assets and contract termination costs of $6 million in consideration of other services.

China Operations. For the year ended December 31, 2013, total operating expenses for China operations decreased by $9 million compared to the same period in 2012. This overall decrease is consistent with the 18% decrease in production volumes in 2013 compared to 2012.

Interest Expense. The following table presents information about interest expense for each of the following years ended
December 31:

	2014	2013	2012
	(In millions)		
Gross interest expense:			
Credit arrangements	$10	$11	$9
Senior notes	101	101	73
Senior subordinated notes	89	93	122
Other	—	—	1
Total gross interest expense	200	205	205
Capitalized interest	(53)	(53)	(68)
Net interest expense	$147	$152	$137

Gross interest expense decreased slightly in 2014 as compared to 2013, due to the redemption of our 7 % Senior Subordinated Notes due 2018 in October 2014. Gross interest expense remained flat in 2013 as compared to 2012 due to the restructuring of our senior notes in 2012. See Note 9, “Debt,” to our consolidated financial statements in Item 8 of this report.

Interest expense associated with oil and gas properties excluded from amortization is capitalized into oil and gas properties. The average balance of oil and gas properties excluded from amortization was consistent for the first three quarters of 2014 resulting in flat capitalized interest in 2014 as compared to 2013. We expect to see less capitalized interest in 2015 due to the reduction of oil and gas properties excluded from amortization at December 31, 2014. Capitalized interest decreased in 2013 as compared to 2012, due to a reduction in our average balance of oil and gas properties excluded from amortization.

Commodity Derivative Income (Expense). The fluctuations in commodity derivative income (expense) from period to period are due to the volatility of oil and natural gas prices and changes in our outstanding derivative contracts during these periods. Commodity derivative income for the year ended December 31, 2014 was $610 million, which was primarily comprised of unrealized gains of $649 million related to the change in value of derivative contracts due to changes in commodity prices, offset by $39 million of realized losses associated with derivative contract settlements. Commodity derivative expense for the year ended December 31, 2013 was $97 million, which was primarily comprised of unrealized losses of $157 million related to the change in value of derivative contracts due to changes in commodity prices, offset by $60 million of realized gains associated with derivative contract settlements.

See Note 5, "Derivative Financial Instruments," and Note 8, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report.

Taxes. The effective tax rates for continuing operations for the years ended December 31, 2014, 2013 and 2012 were 37%, 64% and 33%, respectively. Our effective tax rate for all periods was different than the federal statutory rate of 35% due to non-deductible expenses, state income taxes, the differences between international and U.S. federal statutory rates, and the impact of our China earnings being taxed both in the U.S and China. This double taxation is a byproduct of our federal net operating loss (NOL) position which limits our ability to utilize related foreign tax credits (FTC) until our remaining NOLs are utilized. As a result of our earnings in China being taxed in both the U.S. and China, we expect our effective tax rate for future China earnings to be approximately 60%. We expect the U.S. portion of the rate to be a 35% tax rate, all of which is expected to be deferred taxes.

Our effective tax rate for our domestic operations generally approximates 37%. For the year ended 2014, our effective tax rate was 37% for continuing operations as the majority of our income from continuing operations resulted from our domestic business, which was only taxable in the U.S. As a result of our December 2012 decision to repatriate earnings from our international operations, we experienced fluctuation in our effective tax rates in 2013 and 2012 due to these earnings being taxed both in the U.S. and the local countries. Please see the discussion and tables in Note 10, “Income Taxes,” to our consolidated financial statements in Item 8 of this report.

Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices; the timing, amount and location of future production; operating expenses; and capital costs.

Results of Discontinued Operations - Malaysia

Revenues and Liftings. Our Malaysia revenues were primarily from the sale of crude oil. Substantially all of the crude oil from our offshore Malaysia operations was produced into FPSOs and "lifted" and sold periodically as barge quantities were accumulated. Revenues were recorded when oil was lifted and sold, not when it was produced into FPSOs or onshore storage terminals. As a result, timing of liftings impacted period-to-period results. In February 2014, we closed the sale of our Malaysia business. See Note 1, “Organization and Summary of Significant Accounting Policies” and Note 3, “Discontinued Operations,” to our consolidated financial statements appearing in Item 8 of this report for additional information regarding the sale.

For the year ended December 31, 2014, revenues from discontinued operations of $90 million were 89% lower than 2013, due to the sale of our Malaysia business in February 2014. Revenues of $823 million for 2013 were 18% lower than 2012, primarily due to fewer liftings of crude oil. The average realized price per BOE remained essentially flat during 2012, 2013 and 2014 through the close date of the sale. Our 2013 total liftings decreased 18% as compared to 2012. Approximately 65% of the decrease in liftings was due to natural decline. The remainder of the decrease was due to the timing of liftings and the terms of the production sharing contracts (PSCs) in Malaysia, which reduced entitled production as we reached certain cost recovery milestones.

The following table reflects our production and average realized commodity prices from discontinued operations for each of the following years ended December 31:

	2014	2013	2012
Production/Liftings:[1]			
Crude oil and condensate (MBbls)	822	7,510	9,103
Natural gas (Bcf)	—	0.5	1.2
Total (MBOE)	822	7,600	9,295
Average Realized Prices:			
Crude oil and condensate (per Bbl)	$ 109.86	$ 109.20	$ 109.95
Natural gas (per Mcf)	—	3.65	3.89
Crude oil equivalent (per BOE)	109.86	108.17	108.17

(1) Represents our net share of volumes sold regardless of when produced.

Operating Expenses. The following tables present information about our operating expenses for our discontinued operations.

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Year ended December 31, 2014 compared to December 31, 2013

	Unit-of-Production Year Ended December 31,		Percentage Increase (Decrease)	Total Amount Year Ended December 31,		Percentage Increase (Decrease)
	2014	2013		2014	2013	
	(Per BOE)			(In millions)		
Lease operating	$ 13.76	$ 15.39	(11)%	$ 11	$ 117	(90)%
Production and other taxes	31.16	35.85	(13)%	25	272	(91)%
Depreciation, depletion and amortization	39.30	32.17	22 %	33	245	(87)%
General and administrative	—	2.31	(100)%	—	18	(100)%
Total operating expenses	84.22	85.71	(2)%	69	652	(89)%

Our total operating expenses for discontinued operations for 2014 decreased $583 million compared to the same period of 2013 as a result of the sale of our Malaysia business in February 2014.

Year ended December 31, 2013 compared to December 31, 2012

	Unit-of-Production Year Ended December 31,		Percentage Increase (Decrease)	Total Amount Year Ended December 31,		Percentage Increase (Decrease)
	2013	2012		2013	2012	
	(Per BOE)			(In millions)		
Lease operating	$ 15.39	$ 10.89	41 %	$ 117	$ 101	16 %
Production and other taxes	35.85	27.82	29 %	272	259	5 %
Depreciation, depletion and amortization	32.17	26.94	19 %	245	251	(2)%
General and administrative	2.31	0.75	208 %	18	7	151 %
Total operating expenses	85.71	66.40	29 %	652	618	6 %

Our operating expenses for discontinued operations for 2013, stated on a per BOE basis, increased 29% over 2012. The components of the period-to-period change are as follows:

- LOE per BOE increased 41% ($4.50 per BOE) due to increased service costs related to offshore support operations in Malaysia and mostly-fixed fees associated with producing into onshore storage terminals in Malaysia combined with fewer liftings.
- Production and other taxes per BOE increased 29% due to the terms of the PSCs in Malaysia, which increased production tax rates subsequent to reaching certain cost recovery milestones.
- DD&A expense decreased 2% due to an 18% decrease in liftings during 2013 as compared to 2012, partially offset by an increase in the average DD&A rate. Our DD&A rate per BOE increased 19% in 2013 compared to 2012 due primarily to upward revisions of asset retirement costs in 2013 for Malaysia and the costs of unsuccessful wells in offshore Malaysia being included in costs subject to amortization in the second quarter of 2013 without a related increase in reserves.
- G&A expense increased approximately $11 million ($1.56 per BOE) primarily due to increased employee-related costs and other costs associated with our decision to sell our Malaysia business.

Liquidity and Capital Resources

The following discussion is inclusive of both our continuing and discontinued operations, unless otherwise noted.

We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this through drilling programs and property acquisitions, which require substantial capital expenditures. Sustained lower prices for oil, natural gas and NGLs will reduce the amount of oil and gas that we can economically produce and will affect the amount of cash flow available for capital expenditures. Sustained lower commodity prices may also impact our ability to borrow and raise additional capital, as further described below.

We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are created based upon our estimate of internally generated sources of cash, as well as the available borrowing capacity of our revolving credit facility and money market lines of credit.

During the fourth quarter of 2014 and continuing into the first quarter of 2015, crude oil prices declined significantly primarily due to global supply and demand imbalances. Given the future uncertainty regarding the timing and magnitude of an eventual recovery of crude oil prices, we have reduced our planned capital spending for 2015 to more closely match our expected cash flows and have decided to optimize long-term liquidity preservation over short-term reserve and production growth. We expect our 2015 budget will be financed through our cash flows from operations (inclusive of realized derivative contract gains and losses) and borrowings under our credit facility, as needed. Approximately 82% of our expected 2015 domestic oil and gas sales (excluding NGLs) supporting the current 2015 capital budget are partially protected against oil and gas price volatility using derivative contracts. For further discussion of our derivative activities, see Note 5, "Derivative Financial Instruments," to our consolidated financial statements in Item 8 of this report. Our 2015 capital budget, excluding estimated capitalized interest and direct internal costs of approximately $120 million, is expected to be approximately $1.2 billion.

At December 31, 2014, the values of our U.S. and China cost center ceilings were calculated based upon SEC pricing of $4.35 per MMBtu for natural gas and $94.98 per barrel for oil. Using these prices, our ceilings for the U.S. and China exceeded the net capitalized costs of oil and gas properties by approximately $400 million and $150 million, respectively, net of tax, and as such, no ceiling test writedown was required. Holding all other factors constant, it is likely that we will experience a ceiling test writedown in the U.S. and China in the first quarter of 2015. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, upward or downward reserve revisions, reserve adds, and tax attributes. Subject to these numerous factors and inherent limitations, we believe that an impairment in the first quarter of 2015 could exceed $750 million. Once recorded, a ceiling test writedown is not reversible at a later date even if oil and gas prices increase.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results; oil, natural gas and NGL prices; industry conditions; the prices and availability of goods and services; and the extent to which properties are acquired or non-strategic assets are sold. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. We believe we have the operational flexibility to react quickly with our capital expenditures to changes in circumstances or fluctuations in our cash flows.

We continuously monitor our liquidity needs, coordinate our capital expenditure program with our expected cash flows and projected debt-repayment schedule, and evaluate our available alternative sources of liquidity, including accessing debt and equity capital markets in light of current and expected economic conditions. We believe that our liquidity position and ability to generate cash flows from our operations will be adequate to fund 2015 operations and continue to meet our other obligations.

Credit Arrangements and Other Financing Activities. We maintain a revolving credit facility of $1.4 billion that matures in June 2018, as well as money market lines of credit of $195 million. At December 31, 2014, we had $345 million of LIBOR based loans outstanding against our revolving credit facility and $101 million outstanding against our money market lines of credit. In October 2014, we completed the redemption of our $600 million aggregate principal of 7 % Senior Subordinated Notes due 2018. The transaction included a premium payment of approximately

$14 million. At December 31, 2014, we had no scheduled maturities of senior or senior subordinated notes until 2020. For a more detailed description of the terms of our credit arrangements and senior and senior subordinated notes, please see Note 9, “Debt,” to our consolidated financial statements in Item 8 of this report.

Our credit facility has restrictive financial covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 and maintenance of a ratio of earnings before gain or loss on the disposition of assets, interest expense, income taxes and certain noncash items to interest expense of at least 3.0 to 1.0. At December 31, 2014, we were in compliance with all of our debt covenants. We entered this challenging commodity price environment with strong debt covenant-related financial ratios and do not foresee this changing in 2015. For a more detailed description of the terms of our credit arrangements, please see Note 9, “Debt ,” to our consolidated financial statements in Item 8 of this report.

As of February 20, 2015, we had outstanding borrowings of $610 million and available borrowing capacity of approximately $790 million under our revolving credit facility. In addition, we had outstanding borrowings under our money market lines of credit of $85 million.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments as well as the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital.

At December 31, 2014 and 2013, we had negative working capital of $161 million and $389 million, respectively. The changes in our working capital from 2013 to 2014 are primarily a result of a $485 million increase in the fair value of our current net derivative asset during 2014 combined with working capital reductions associated with the sale of our Malaysia business (February 2014) and our Granite Wash assets (September 2014). The remaining change is due to the timing of the collection of receivables; the timing of crude oil liftings in our China operations; drilling activities; payments made by us to vendors and other operators; and the timing and amount of advances received from our joint operations.

Cash Flows from Operations. Our primary source of capital and liquidity are cash flows from operations, which are primarily affected by the sale of oil, natural gas and NGLs, as well as commodity prices, net of the effects of settled derivative contracts, as well as changes in working capital.

Our net cash flows from operations were approximately $1.4 billion in 2014 (includes $3 million of cash flows from our Malaysia discontinued operations), $1.4 billion in 2013 and $1.1 billion in 2012. Despite selling our Malaysia business, which provided approximately $249 million of our 2013 cash flows from operations, our 2014 cash flows from operations were relatively flat compared to 2013. This is a result of increased domestic production, strong pricing during the first nine months of the year and a $0.42 per BOE decrease in domestic operating expenses (excluding non-cash DD&A expense) during the year.

Cash Flows from Investing Activities. Net cash used in investing activities for 2014 was $660 million compared to $2.1 billion for 2013. The decrease in net cash used in 2014 investing activities is primarily due to net proceeds of $809 million received from the sale of our Malaysia business and proceeds of approximately $620 million from the sale of our Granite Wash and other assets. Our investment levels in our oil and gas properties were relatively consistent during 2014 and 2013 as we executed our plan in a stable commodity price environment into third quarter 2014. Due to the dramatic commodity price decline in fourth quarter 2014, we expect a significant decrease in our investments during 2015.

Cash Flows from Financing Activities. Net cash used in financing activities for 2014 was $808 million compared to net cash provided by financing activities of $620 million for 2013. During 2014, we reduced our outstanding borrowings under our revolving credit facility and money market lines of credit by $203 million and redeemed our $600 million aggregate principal of 7 % Senior Subordinated Notes due 2018 using the proceeds from the sale of our Granite Wash assets.

Capital Expenditures. Our capital investments for continuing operations for 2014 increased 5% compared to 2013, due to accelerating the development of our domestic assets during 2014. The table below summarizes our capital investments.

	Twelve Months Ended December 31,	
	2014	2013
	(In millions)	
Continuing operations:		
Exploitation and development	$1,411	$1,391
Exploration (exclusive of exploitation and leasehold)	346	249
Acquisitions	33	72
Leasing proved and unproved property (leasehold)	119	90
Pipeline spending	9	20
Plug and abandonment settlements	8	8
Total continuing operations	1,926	1,830
Discontinued operations	12	199
Total	$1,938	$2,029

Contractual Obligations

The table below summarizes our significant contractual obligations due by year as of December 31, 2014.

	Total	Year Ended December 31,