NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 24, 2016

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, 2015

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, 2015 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 19, 2016, there were 163,633,331 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 17, 2016, 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, estimates of reserves, projected production, estimates of operating costs, planned exploratory or developed drilling, projected cash flows and liquidity, business strategy 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,” “project,” “target,” “goal,” “plan,” “should,” “will,” “predict,” “potentia
expressions that convey the uncertainty of future events 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 but not limited to, the following:

- oil, natural gas and natural gas liquids prices;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- legislation or regulatory initiatives intended to address seismic activity;
- the timing and our success in discovering, producing and estimating reserves;
- sustained decline in commodity prices resulting in writedowns of assets;
- ability to develop existing reserves or acquire new reserves;
- the availability and volatility of the securities, capital or credit markets and the cost of capital;
- maintaining sufficient liquidity to fund our operations and business strategies;
- the accuracy of and fluctuations in our reserves estimates due to sustained low commodity prices, incorrect assumptions and other causes;
- 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, seismicity 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 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, instrument terms 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;
- our ability to monetize non-strategic assets, repay or refinance our existing indebtedness and the impact of changes in our investment ratings;
- labor conditions;
- weather conditions;
- competitive conditions;
- terrorism or civil or political unrest in a region or country;
- electronic, cyber or physical security breaches;
- changes in tax rates;
- inflation rates;
- 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 under the caption "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates."

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 is a large independent exploration and production company, with estimated consolidated proved reserves of approximately 509 million barrels of oil equivalent. Approximately 98% of our proved reserves and approximately 90% of our daily production are located in the United States. We are a Delaware corporation that was incorporated in 1988 and has been publicly traded on the New York Stock Exchange (NYSE) since 1993. We have been a member of the S&P 500 Index since 2010. Our operations are focused primarily on large scale, onshore liquids-rich resource plays in the United States. Our principal areas of operation are the Anadarko and Arkoma basins of Oklahoma, the Williston Basin of North Dakota, the Uinta Basin of Utah and the Maverick and Gulf Coast basins of Texas. In addition, we have oil developments offshore China.

Newfield has undergone significant change over the last decade. We have transitioned from a diversified asset base of onshore, offshore and international operations to a more focused portfolio of onshore liquids-rich resource plays with extensive drilling inventories. Furthermore, we have transitioned our proved reserves and production from primarily natural gas to a greater percentage of oil and natural gas liquids. Our corporate vision is clear: to be recognized as the premier independent E&P company, delivering operational excellence, top-tier business results and value to our shareholders, employees and the communities in which we live and work.

Executive Summary

- Reduced our 2015 capital investments by 26% compared to 2014 and re-directed capital to our highest return region – the Anadarko Basin of Oklahoma;

- Increased 2015 domestic production by 6% over 2014 to 50.6[1] MMBOE. Grew domestic liquids production by 12% year-over-year. Consolidated fourth quarter production was 162[2] MBOEPD (64% liquids);

- Approximately 98% of our year-end 2015 estimated proved reserves of 509 MMBOE (41% oil, 16% NGLs and 43% natural gas) are located onshore in the United States;

- The Company has a nine-year reserve life index (based on 2015 production levels);

- Our proved reserves at year-end 2015 were negatively impacted by the significant drop in commodity prices. Due to price-related revisions, domestic liquids reserves decreased 21% year-over-year and represent 56% of domestic proved reserves. Total company and domestic PV-10[3] decreased 67% to $2.9 billion and 65% to $2.7 billion, respectively over the prior year-end. At year-end 2015, approximately 65% of domestic and consolidated reserves were proved developed;

- The Anadarko Basin is our largest producing region, averaging production of approximately 75 MBOEPD net in the fourth quarter of 2015. At year-end 2015, the Anadarko Basin comprised 53% of our total proved reserves, and we had interest in more than 315,000 net acres in SCOOP and STACK;

- Our Pearl development, located in the South China Sea, was producing approximately 13 MBOPD net at year-end 2015;

- Due to service cost reductions and continued operational efficiencies, our average domestic lease operating expenses for 2015, on a per barrel basis, decreased 27% from 2014;

- We reduced our overall workforce in 2015 by more than 20% through reductions in personnel, the closure of our Denver office and the subsequent consolidation of two business units into one location adjacent to our headquarters in

The Woodlands, Texas;

- Issued 25.3 million additional shares of common stock through a public equity offering and received net proceeds of approximately $815 million in the first quarter of 2015, which were used primarily to repay all borrowings under our credit facility and money market lines of credit;

- Issued $700 million 5 % Senior Notes due 2026 through a public debt offering and received net proceeds of $691 million in March 2015. In April 2015, we used the proceeds and cash on hand to redeem the $700 million aggregate

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principal of our 6 % Senior Subordinated Notes due 2020. The transactions lowered our expected annual interest expense by $9 million; and

- Amended our credit facility in March 2015 to increase its capacity from $1.4 billion to $1.8 billion and extended the maturity date to June 2020.

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(1) Includes 7.7 Bcf of natural gas produced and consumed in operations.

(2) Includes 1.7 Bcf (3 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.

2016 Outlook

Our industry has been significantly impacted by lower crude oil and natural gas prices. Following a five-year period of unprecedented strength and consistency from 2010 through most of 2014, oil prices began collapsing in late 2014 and averaged approximately $49 per barrel (NYMEX WTI) in 2015. In this period of commodity price uncertainty, we have adapted our near-term business strategies to preserve liquidity and financial strength.

Although Newfield and other domestic producers curtailed capital investments in 2015 and many long-lead global developments around the world have been slowed or canceled, the global oil markets remain oversupplied, and the outlook for oil prices in 2016 has not improved. As of February 19, 2016, NYMEX WTI was approximately $30 per barrel and the three-year forward curve averaged $41 per barrel. Domestic natural gas prices remain weak as well. As of February 19, 2016, NYMEX Henry Hub was approximately $1.80 per MMBtu and the three-year forward curve averaged $2.45 per MMBtu. We expect that industry budgets will be significantly lower in 2016 and will remain so until commodity prices strengthen and profit margins improve.

In response to this commodity price environment, we have significantly reduced our planned capital spending in 2016 to approximately $625-$675 million (excluding approximately $100 million of capitalized interest and direct internal costs), a decrease of more than 50% from 2015 investment levels. We expect to fund our 2016 investments through cash flows from operations, borrowings under our credit facility, non-strategic asset sales or potentially accessing the public debt and/or equity markets.

Our primary near-term goals include:

- preserving liquidity and financial strength;
- limiting new borrowings and more closely aligning planned capital investments with cash flows;
- high-grading investments based on rates of return;
- holding our acreage by production in the Anadarko Basin; and
- reducing our cash operating costs.

Our 2016 domestic production is expected to be about 49-51 MMBOE, relatively flat when compared to 2015 production levels. Oil production from China is expected to be approximately 4.3 MMBOE in 2016, down about 20% due to natural declines.

Our estimated 2016 capital expenditure budget and estimated production by area are shown below:

The steep reductions over the prior year in our planned capital investments have caused us to make significant changes in our near-term drilling plans. We expect that over 80% of our capital investments will be allocated to the Anadarko Basin's SCOOP and STACK plays. The Anadarko Basin provides the highest returns in our portfolio at low oil and gas prices. We benefited from a lower service cost environment in 2015, and we expect additional cost reductions in 2016.

Our Business Strategy

Our near-term business strategy outlined in the "2016 Outlook" above reflects the continuation of low commodity prices in our three-year plan and our focus on maintaining liquidity and a strong capital structure. Our near-term strategy differs from what we consider our long-term business strategy. Our primary, long-term goal continues to be delivering stockholder value through consistent growth of cash flow, production and reserves. Key components of our business strategy include:

Preserving a strong and flexible capital structure. Maintaining a strong capital structure that protects our balance sheet and liquidity remains central to our business strategy. For 2016, our goal will be to continue to preserve financial flexibility through strong credit metrics and ample liquidity as we seek to manage the continued weakness in both oil and gas prices. Our capital program is flexible and frequently adjusted to reflect fluctuations in commodity markets. Over the last several years, we have divested non-strategic assets and used derivatives to protect a portion of our future production from commodity price volatility to ensure adequate funds were available to execute our drilling programs. In the first quarter of 2015, we issued 25.3 million additional shares of common stock through a public equity offering and received net proceeds of approximately $815 million, which were used primarily to repay all borrowings under our credit facility and money market lines of credit. In addition, we issued $700 million 5 % Senior Notes due 2026 through a public debt offering and received net proceeds of $691 million in March 2015. We used the proceeds and cash on hand to redeem the $700 million aggregate principal of our 6 % Senior Subordinated Notes due 2020. In March 2015, we amended our credit facility to increase the capacity from $1.4 billion to $1.8 billion and extend the maturity date to June 2020.

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. In 2015, we reduced our average well costs in all areas through faster drilling times and innovative optimizations of our completions. In addition, reduced service costs have positively impacted our business. We also have multiple initiatives underway to manage our base production, improve operational efficiencies and enhance future margins.

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 onshore in the United States. We believe that by focusing on more than one area, we increase our flexibility to respond to, and limit our exposure to, the volatility and unique risks our industry faces, such as geologic, political and regional price risks. In line with this element of our strategy and the current weakness in commodity prices, over 80% of our 2016 capital investments will be focused on the SCOOP and STACK.

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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 2015 we divested approximately $2.2 billion of non-strategic assets, which we used to fund drilling and reduce borrowings.

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 based on 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 are focused on liquids-rich onshore resource plays in the United States. Our domestic plays represent approximately 98% of our estimated consolidated proved reserves at year-end 2015. The remaining 2% of our proved reserves at year-end 2015 are attributable to our offshore developments in China. In response to the weakness in crude oil prices and in an effort to balance planned capital investments with cash flows, we have ceased or slowed development activities in all areas. Substantially all of our acreage outside the Anadarko Basin is held by production and we have the option to resume activity levels when commodity prices strengthen.

Anadarko Basin. SCOOP and STACK have been our fastest growing plays over the last three years. At year-end 2015, the Anadarko Basin represented more than half of our domestic proved reserves and daily production. After recent additions, we held more than 315,000 net acres in SCOOP and STACK at year-end 2015. Our average net production from the basin in the fourth quarter of 2015 was approximately 75 MBOEPD (35% oil and 26% NGLs), an increase of 39% compared to the fourth quarter of 2014.

Arkoma Basin. We have significant dry gas production in the Arkoma Basin, representing approximately 13% of our total consolidated proved reserves at year-end 2015. 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, 2015, we had approximately 146,000 net acres in the Arkoma Basin and our net production for the fourth quarter of 2015 was approximately 16 MBOEPD (99% dry gas).

Uinta Basin. We have approximately 215,000 net acres in the Uinta Basin, which represents about 16% of our consolidated proved reserves at year-end 2015. Our Uinta Basin 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. We have taken significant steps to reduce our operating expenses in the GMBU. Although we are not actively drilling development wells today, we continue to inject water into the GMBU to advance the waterflood development. Our net production from the Uinta Basin during the fourth quarter of 2015 averaged approximately 20 MBOEPD (82% oil and 2% NGLs), a decrease of 21% as compared to the fourth quarter of 2014.

Williston Basin. We have approximately 85,000 net acres in the Williston Basin. This basin represents about 10% of our consolidated proved reserves at year-end 2015. Fourth quarter 2015 net production averaged approximately 20 MBOEPD (67% oil and 15% NGLs), which is flat compared to the fourth quarter of 2014.

Eagle Ford. About 4% of our consolidated proved reserves at year-end 2015 are located in the Eagle Ford shale. This area contains approximately 35,000 net acres. Production averaged 10 MBOEPD (46% oil and 29% NGLs) during the fourth quarter of 2015, which is down 2% from the fourth quarter of 2014.

China. Approximately 10 MMBOE, or 2%, of our proved reserves at year-end 2015 are located in offshore China. Our Pearl development, located in the South China Sea, had average net production of 13 MBOPD in the fourth quarter 2015. No additional development drilling is planned at Pearl and cash flow from China is being used to fund our domestic drilling programs.

Other. Over the last several years, we slowed our activities in our Gulf Coast conventional natural gas plays and have sold numerous non-strategic assets. Fourth quarter 2015 net production averaged approximately 5 MBOEPD. We expect our production in these conventional plays to continue to experience natural declines in 2016 due to limited investment.

Divestitures

During 2015, we received proceeds of approximately $90 million associated with the continuing sale of non-strategic assets. These sales were consistent with our strategy over the last four years to monetize non-strategic assets to improve our focus on domestic resource plays, reduce overall debt and enhance liquidity. Over this period, we received proceeds of approximately $2.2 billion for sales of non-strategic assets.

Reserves

Estimates of Proved Reserves

All reserve information in this report was based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates was 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 industry experience (including over 20 years of experience in reserve estimation).

DeGolyer and MacNaughton (D&M) and Ryder Scott Company (Ryder Scott) performed an audit of the internally prepared reserve estimates on certain fields aggregating to 94% of 2015 year-end reported proved reserve quantities on a barrel of oil equivalent basis. The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates. Newfield's proved reserves are, in the aggregate, reasonable and within the established audit tolerance guidelines of 10 percent. The reports of D&M dated January 20, 2016, and Ryder Scott dated January 12, 2016, contain further discussion of the reserve estimates and their audit procedures, as well as the qualifications of the technical person primarily responsible for overseeing such estimates. Both reports are attached as exhibits to this annual report and incorporated herein by reference. See Exhibits 99.1 and 99.2.

Our reserves estimates were made using available geological and reservoir data as well as production performance data. These estimates 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, marketing agreements, 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 their 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, natural 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.

The table below summarizes our estimates of proved reserves at December 31, 2015.

	Proved Reserves (MMBOE)	Percentage of Proved Reserves	
Domestic:			
Anadarko Basin	269	53	%
Arkoma Basin	64	13	%
Uinta Basin	81	16	%
Williston Basin	52	10	%
Eagle Ford	21	4	%
Other	12	2	%
Total domestic	499	98	%
International:			
China	10	2	%
Total	509	100	%

The following table shows a summary of our estimates of proved oil and gas reserves by country at December 31, 2015.

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
Proved Developed Reserves:				
Domestic	115	942	47	319
China	10	—	—	10
Total proved developed	125	942	47	329
Proved Undeveloped Reserves:				
Domestic	82	363	37	180
China	—	—	—	—
Total proved undeveloped	82	363	37	180
Total proved reserves	207	1,305	84	509

Total Proved Reserves

Our estimates of proved reserves and related PV-10 and standardized measure of future net cash flows as of December 31, 2015 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 SEC pricing of crude oil, domestic natural gas and NGLs has declined substantially since December 2014. Sustained lower prices will result in future SEC pricing being 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 ceiling tests and volume-dependent depletion cost calculations.

Our year-end 2015 proved reserves of 509 MMBOE consisted of 309 MMBOE proved developed producing, 20 MMBOE proved developed non-producing and 180 MMBOE proved undeveloped reserves. Our proved liquids reserves at year-end 2015 were 291 million barrels, compared to 377 million barrels at year-end 2014, a decrease of 23%. During 2015, crude oil and condensate reserves decreased 94 million barrels while NGL reserves increased 8 million barrels. At year-end 2015, 71% of our proved liquids reserves were crude oil or condensate. At December 31, 2015, our proved natural gas reserves were 1,305 Bcf, a 19% decrease compared to 2014.

At December 31, 2015, the SEC pricing for natural gas was $2.59 per MMBtu, a 40% decrease compared to the prior year end, and pricing for oil was $50.11 per barrel, a 47% decrease compared to the prior year end. As a result, we revised our total proved reserves downward by 286 MMBOE for pricing changes; however, with cost structure improvement we were able to recapture 88 MMBOE. During 2015, we had a positive 24 MMBOE performance revision primarily associated with the

Anadarko Basin. Through infill drilling revisions we added 18 MMBOE. Due to capital re-allocation, we had a downward revision of 18 MMBOE associated with remaining proved undeveloped locations.

During 2015, we added 101 MMBOE through extensions, discoveries and other additions. Consistent with our continued focus on domestic liquids, our 2015 additions were entirely domestic and 69% liquids (49 MMBbls of oil and 20 MMBbls of NGLs). During 2015, we purchased 1 MMBOE and divested 8 MMBOE.

Proved Undeveloped Reserves

Our estimates of proved undeveloped reserves at December 31, 2015 were 180 MMBOE compared to 307 MMBOE at December 31, 2014. Liquids comprised 66% of our total proved undeveloped reserves at December 31, 2015. SCOOP and STACK represented 31% and 48% of our year-end proved undeveloped reserves, respectively. During 2015, we invested approximately $600 million of drilling, completion and facilities-related capital to convert 61 MMBOE of our December 31, 2014 proved undeveloped reserves into proved developed reserves. In 2015, we had negative price revisions of 242 MMBOE, which were partially offset by commensurate lower service costs, improved well performance and infill drilling revisions of 106 MMBOE. During 2015, we added 75 MMBOE of new proved undeveloped reserves through extensions, discoveries and other additions. Sales and acquisitions in 2015 led to a 5 MMBOE net decrease. We continually assess the economic viability of our proved undeveloped reserves and direct capital resources to develop the areas that will provide the highest rate of return.

Estimates of proved undeveloped reserve quantities are limited by development drilling activity we intend to undertake during the 2016-2020 five-year period. For additional information regarding the changes in our proved reserves, see our “Supplementary Financial Information — Supplementary Oil and Gas Disclosures” in Item 8 of this report.

During the years 2013, 2014 and 2015, we developed 12%, 22% and 20%, respectively, of our prior year-end proved undeveloped reserves. The Company annually reviews all proved undeveloped reserves to ensure an appropriate development plan exists. 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 2016 could also render some of our proved undeveloped reserves uneconomic at future SEC pricing or compel us to reevaluate our project commitments to certain development projects.

Reserves Sensitivities

The following sensitivity table was provided to illustrate the estimated impact on our proved reserve volumes and value. The sensitivity reflects crude oil and natural gas pricing that is approximately 20% lower than SEC pricing at December 31, 2015. In addition to different price assumptions, the sensitivity below includes 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.

The sensitivity case demonstrates the impact that a lower price and cost environment may have on proved reserves volumes and PV-10. There is no assurance that these prices or cost savings will be achieved.

	Actual at December 31, 2015	Sensitivity Using Lower Prices
Crude oil price (per Bbl)	$ 50.11(1)	$ 40.00(2)
Natural gas price (per MMBtu)	$ 2.59(1)	$ 2.00(2)
Capital expenditure reduction	n/a	10 %
Operating expense reduction	n/a	10 %
Proved developed reserves (MMBOE)	329	315
Proved undeveloped reserves (MMBOE)	180	165
Total proved reserves (MMBOE)	509	480
Proved reserve PV-10 value (before tax, in millions)	$ 2,940	$ 1,603
Present value of future income tax expense	164	66
Standardized measure of discounted future net cash flows	$ 2,776	$ 1,537

(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. PV-10 is used in the oil and natural gas industry 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:

	Domestic (In millions)	China	Total
December 31, 2015:			
Proved reserve PV-10 value (before tax)	$2,718	$222	$2,940
Present value of future income tax expense	164	—	164
Standardized measure of discounted future net cash flows	$2,554	$222	$2,776
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

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 two largest fields, SCOOP and STACK, accounted for approximately 53% of the total net present value of our proved reserves at December 31, 2015.

	Percentage of Proved Reserves
Ten largest fields	92%
Two largest fields	53%

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 two 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,		
	2015	2014	2013
Production:			
Crude oil and condensate (MBbls)			
SCOOP	3,779	2,548	1,323
STACK	3,645	1,182	513
Natural gas (Bcf)			
SCOOP	43.2	34.5	16.8
STACK	11.0	3.6	2.5
NGLs (MBbls)			
SCOOP	4,871	4,762	1,888
STACK	1,396	458	230
Total production by field (MBOE)			
SCOOP	15,857	13,066	5,999
STACK	6,886	2,245	1,160
Average Realized Prices:[1]			
Crude oil and condensate (per Bbl)			
SCOOP	$42.67	$85.66	$93.75
STACK	42.99	84.13	94.22
Natural gas (per Mcf)			
SCOOP	$2.38	$3.96	$3.35
STACK	2.49	4.44	3.56
NGLs (per Bbl)			
SCOOP	$18.97	$29.54	$31.62
STACK	19.02	35.24	34.74
Average realized prices by field (per BOE)			
SCOOP	$22.49	$37.94	$40.01
STACK	30.61	58.65	56.19
Average Production Cost:[2]			
SCOOP			
Lease operating costs (per BOE)	$1.33	$1.93	$2.91
Transportation costs (per BOE)	4.15	2.65	1.47
STACK			
Lease operating costs (per BOE)	$2.58	$5.42	$7.56
Transportation costs (per BOE)	2.04	1.93	1.73

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

(2) Production costs include cost to operate and maintain our wells, related equipment, and supporting facilities, including the cost of labor, well service and repair, gathering, processing, transportation, as well as production-related general and administrative costs. Severance taxes and property taxes are excluded from production costs.

Drilling Activity

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

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive	123	57	254	114	297	118
Nonproductive	1	1	—	—	1	1
China:						
Productive	—	—	—	—	—	—
Nonproductive	—	—	1	1	1	1
Malaysia:(1)						
Productive	—	—	—	—	2	1
Nonproductive	—	—	—	—	—	—
Exploratory well total	124	58	255	115	301	121
Development wells:						
Domestic:						
Productive	158	78	326	231	237	184
China:						
Productive	16	3	2	1	3	1
Malaysia:(1)						
Productive	—	—	—	—	12	8
Development well total	174	81	328	232	252	193

(1) Classified as discontinued operations.

We were in the process of drilling 65 gross (27 net) exploration or development wells domestically at December 31, 2015. In process well activity increased at year end due to wells pending completion activities.

Productive Wells

As of December 31, 2015, 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	2,822	2,277	764	57	3,586	2,334
Natural gas	1,075	837	500	98	1,575	935
China:						
Oil	6	3	63	8	69	11
Total:						
Oil	2,828	2,280	827	65	3,655	2,345
Natural gas	1,075	837	500	98	1,575	935
Total	3,903	3,117	1,327	163	5,230	3,280

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 tables list by geographic area interests we owned in developed and undeveloped oil and gas acreage at December 31, 2015, 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 production sharing contracts.

Total Acreage

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Anadarko Basin	263	167	246	156
Arkoma Basin	226	144	3	2
Uinta Basin	179	109	179	108
Williston Basin	116	70	24	14
Eagle Ford	51	34	2	2
Other	610	231	321	265
Total domestic	1,445	755	775	547
China:	34	9	—	—
Total	1,479	764	775	547

Expiring Acreage

	Undeveloped Acres Expiring									
	2016		2017		2018		2019		2020	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Anadarko Basin	66	42	84	54	31	20	—	—	—	—
Uinta Basin	19	11	43	26	15	9	15	9	4	2
Williston Basin	12	7	—	—	2	1	—	—	—	—
Eagle Ford	1	1	—	—	1	1	—	—	—	—
Other	53	33	126	77	104	66	23	15	18	11
Total	151	94	253	157	153	97	38	24	22	13

At December 31, 2015, we owned mineral interests in 454,000 gross and 113,000 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, joint development agreements, ordinary course liens incidental to operating agreements and for current taxes, development obligations under oil and gas leases or capital commitments under our production sharing contracts in China. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than the title investigation 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 examinations 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. Please see further discussion under "Contractual Obligations" in Item 7 of this report.

Competition

Competition in the oil and gas industry is intense, particularly with respect to the acquisition of properties and access to capital and credit markets. 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 17, “Segment Information,” to our consolidated financial statements in Item 8 of this report.

Employees

As of February 19, 2016, we had 1,111 employees. All but 53 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;

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- 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 Bureau of Indian Affairs, the Office of Natural Resources Revenue or the Bureau of Land Management, or BLM, all federal agencies. BLM leases contain relatively standardized terms and require compliance with detailed 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 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 occupational 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).

Oil and gas activities in certain areas have been opposed by environmental groups and, in certain areas, have 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 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, or CWA, and analogous state and tribal laws. The CWA prohibits any discharge of pollutants into waters of the United States, including wetland areas, except in compliance with permits issued by federal and state governmental agencies. In September 2015, new U.S. Environmental Protection Agency, or the EPA, and U.S. Army Corps of Engineers, or the Corps, rules defining the scope of the EPA’s and the Corps’ jurisdiction became effective. To the extent the rule expands the scope of the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. The process for obtaining permits has the potential to delay the development of natural gas and oil projects. 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.

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. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, from time to time various environmental groups have challenged the EPA's exemption of certain oil and gas wastes from RCRA. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste, if they have hazardous characteristics.

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 federal 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 air pollutants, and is considering the expanded regulation of existing air pollutants and additional air pollutants. For example, in October 2015 the EPA lowered the National Ambient Air Quality Standard, or NAAQS, for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. 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 SDWA also regulates saltwater disposal wells under the Underground Injection Control Program. Recent concerns related to the operation of saltwater disposal wells and induced seismicity have led some states to impose limits the total volume of produced water such wells can dispose of, order disposal wells to cease operations, or banned the construction of new wells. A lack of saltwater disposal wells in the areas in which we operate could result in increased disposal costs for our operations if we are forced to transport produced water by truck, pipeline, or other method over long distances.

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.

In response to findings that emissions of carbon dioxide, methane and other “greenhouse gases, or GHGs, present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, pre-construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. More recently, in December 2015, the EPA finalized rules added new sources to the scope of the GHG monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers of hydraulically fractured wells. The revisions also include the addition of well identification reporting requirements for certain facilities. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs. Also, in August 2015, the EPA announced proposed rules that would establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, as part of an overall effort to reduce methane emissions by up to 45 percent in 2025. The BLM proposed similar regulations designed to reduce methane emissions for oil and gas activities on federal lands in January 2016 that seek to impose limits on venting and flaring and would require enhanced leak detection and repair programs. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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.

At the federal level, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed in April 2015 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants; and issued in May 2014 an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Also, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including, for example, notice to and pre-approval by BLM of the proposed hydraulic fracturing activities; development and pre-approval by BLM of a plan for managing and containing flowback fluids and produced water recovered during the hydraulic fracturing process; implementation of measures designed to protect usable water from hydraulic fracturing activities; and public disclosure of the chemicals used in the hydraulic fracturing fluid. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision is pending, however.

In addition, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. The adoption of new federal rules or regulations relating to hydraulic fracturing could lead to increased operating costs, delays and curtailment in the pursuit of exploration, development or production activities, which in turn could materially adversely affect our operations. Several governmental reviews are underway that focus on environmental aspects of hydraulic fracturing activities. In June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. The draft report is expected to be finalized after a public comment period and a formal review by EPA’s Science Advisory Board. In addition, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing.

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.

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.

The FERC has issued certain market transparency rules for the gas industry pursuant to its EPAct 2005 authority, which may affect some or all of our operations. The FERC issued a final rule in 2007, as amended by subsequent orders on rehearing (Order 704), which requires wholesale buyers and sellers of more than 2.2 million MMBtu of physical gas in the previous calendar year, including gas producers, gatherers, processors and marketers, to report, on May 1 of each year, beginning in 2009, aggregate volumes of gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices, as explained in Order 704. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704. The FERC has issued a Notice of Inquiry in Docket No. RM13-1-000 seeking comments from the industry regarding whether it should require more detailed information from sellers of gas. It is unclear what action, if any, will result and whether our reporting burden will increase or decrease.

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. The Pipeline and Hazardous Materials Safety Administration and the Federal Railroad Administration also published proposed rules in 2014 supplementing the emergency orders that would enhance existing tank car safety requirements and add sampling and testing requirements for product transported by rail. These developments could increase the costs associated with moving our products by rail.

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 of 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.

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.

Exploration well. 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.

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.

MBOEPD. One thousand barrels of oil equivalent per day.

MBOPD. One thousand barrels of oil per day.

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.

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.

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.”

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 commonly used as a benchmark in oil pricing.

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. Additionally, you can access the electronic copy of our most recent Corporate Responsibility report through our website. 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 particularly applicable to our business and the oil and gas industry in which we operate, which may adversely affect our business, financial condition, results of operations or cash flows. You should carefully consider, in addition to the other information contained in this report, the risks described below. We may experience additional risks and uncertainties not currently known to us or, as a result of development occurring in the future, conditions that we currently deem to be immaterial may also adversely affect our business, financial condition, results of operations or cash flows.

Oil, natural 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, cash flows and future growth, as well as liquidity and ability to access additional sources of capital, depend substantially on prevailing prices for oil, natural gas and NGLs. Sustained lower prices will reduce the amount of oil, natural gas and NGLs that we can economically produce and may result in impairments of our proved reserves or reduction of our proved undeveloped reserves. 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, natural gas and NGLs have historically been, and will likely remain, volatile. For example, record high U.S. oil production has contributed to global oil supply exceeding demand, which has caused oil prices to drop precipitously since September 2014. The price of oil (WTI) in January 2016 averaged approximately $31.78 per barrel, as compared to approximately $95 per barrel in January 2014. Natural gas prices also experienced significant declines in 2014 and 2015, as the NYMEX Henry Hub natural gas price during that period ranged from a high of $6.15 per MMBtu in February 2014 to a low of $1.76 per MMBtu in December 2015. Likewise, NGLs have experienced significant recent declines in realized prices. The price of propane (Mont Belvieu) ranged from a high of $1.73 per gallon in February 2014 to a low of $0.30 per gallon in January 2016 and the price of ethane (Mont Belvieu) ranged from a high of $0.45 per gallon in January 2014 to a low of $0.13 per gallon in December 2015.

The market prices for oil, natural gas and NGLs depend on factors beyond our control. Some, but not all, of the factors that can cause fluctuations include:

- the domestic and foreign supply of, and demand for, oil, natural gas and NGLs;
- domestic and world-wide economic conditions;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;

- military, economic and political conditions in oil and gas producing regions;
- the actions taken by the Organization of Petroleum Exporting Countries (OPEC) and other foreign oil and gas producing nations, including the ability of members of OPEC to agree to and maintain price and production controls;
- the impact of the U.S. dollar exchange rates on oil, natural gas and NGL prices;

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- the price and availability of, and demand for, alternative fuels;
- weather conditions and climate change;
- world-wide conservation measures;
- technological advances affecting energy consumption and production;
- changes in the price of oilfield services and technologies;
- the price and level of foreign imports;
- expansion of U.S. exports of oil, natural gas and/or NGLs;
- the availability, proximity and capacity of transportation, processing, storage and refining facilities;
- the costs of exploring for, developing, producing, transporting and marketing oil, natural gas and NGLs; and
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulations.

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 2016 capital investment plan based on anticipated commodity prices, historical drilling success, and markets for our products. These adjustments are likely to influence our profitability and could adversely affect our business, financial condition, results of operations and cash flows. In addition, our stock price in the market is influenced by fluctuations in oil and gas prices.

Sustained material declines in 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 reserve estimates and the amount of products we can economically produce;
- downgrade or other negative rating action with respect to our credit rating;
- reduce revenues, income and cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; or
- reduce the carrying value of our assets in our balance sheet through ceiling test writedowns.

We may be responsible for decommissioning liabilities for offshore interests we no longer own. Under state and federal law, oil and gas companies are obligated to plug and abandon (P&A) a well and restore the lease to pre-operating conditions after operations cease. U.S. state and federal regulations allow the government to call upon predecessors in interest of oil and gas leases to pay for P&A, restoration and decommissioning obligations if the current operator fails to fulfill those obligations. Moreover, offshore P&A liabilities can be very significant. As part of our strategic shift from offshore Gulf of Mexico operations to onshore U.S. operations, we divested our assets on the outer continental shelf (OCS) in the Gulf of Mexico (GoM). As part of those divestitures, we entered into various arrangements with the purchasers whereby the purchasers assumed our P&A liabilities and other liabilities related to decommissioning such GoM assets. Several onshore and offshore E&P companies have sought bankruptcy protection. For example, in 2012 an offshore operator entered bankruptcy proceedings and sought to discharge its P&A liabilities in bankruptcy. The bankruptcy court allowed the discharge because the government identified a predecessor in interest of the lease to perform the P&A obligations. The predecessor in interest was forced to accept P&A liabilities estimated at over $100 million. If purchasers of our former GoM assets, or any successor owners of those assets, are unable to meet their P&A and other decommissioning obligations due to bankruptcy, dissolution or other related liquidity issues, we may be unable to rely on our arrangements with them to fulfill (or provide reimbursement for) those obligations. In those circumstances, the government may seek to impose the bankrupt entity’s P&A obligations on us and any other predecessors in interest. Such payments could be significant and adversely affect our business, results of operations, financial condition and cash flows.

Moreover, recent changes to the Bureau of Ocean Energy Management’s (BOEM) bonding requirements have the potential to adversely impact the financial condition of operators in the GoM and increase the number of operators seeking bankruptcy protection, given the current commodities market. In September 2015, the BOEM issued draft guidance (the “Draft Guidance”) describing revised supplemental bonding procedures the agency plans to use to impose financial assurance obligations for decommissioning activities on the federal OCS. Once the Draft Guidance is finalized, the BOEM will issue these supplemental

bonding changes in a revised Notice to Lessees (NTL) in replacement of an existing NTL on supplemental bonding that was made effective on August 28, 2008. Among other things, the Draft Guidance proposes to eliminate the "waiver" exemption currently allowed by BOEM, whereby certain operators on the OCS projecting a relatively large net worth and meeting certain other criteria have the option of being exempted from posting bonds or other acceptable assurances for such operator's decommissioning obligations. Currently, qualifying operators may self-insure to meet supplemental bonding requirements, but only so long as the cumulative decommissioning liability amount being self-insured by the operator is no more than 50% of the operator's net worth. Under the Draft Guidance, this waiver option would be eliminated and operators would only be able to self-insure for an amount that is no more than 10% of their tangible net worth. Projected decommissioning costs of operations in the GoM continue to increase, and the declining price of oil and gas has adversely affected the net worth of many operators. BOEM's revisions to its supplemental bonding process could result in the revocation of waivers currently held by the entities to whom we divested our GoM assets. If those entities lose their supplemental bonding waiver, they will have to obtain surety bonds or other forms of financial assurance, the costs of which could be significant. Moreover, BOEM's Draft Guidance is likely to result in the loss of supplemental bonding waivers for a large number of operators on the OCS, which will in turn force these operators to seek additional surety bonds and could, consequently, exceed the surety bond market's ability to provide such additional financial assurance. Operators who have already leveraged their assets as a result of the declining oil market could face difficulty obtaining surety bonds because of concerns the surety may have about the priority of their lien on the operators' collateral. Consequently, BOEM's proposed changes could result in additional operators in the GoM initiating bankruptcy proceedings, which in turn could result in the government seeking to impose P&A costs on predecessors in interest in the event that the current operator cannot meet its P&A obligations. As a result, we could find ourselves liable to pay for the P&A costs of any entity we divested our GoM assets to, which payments could be significant and adversely affect our business, results of operations, financial condition and cash flows.

Legislation or regulatory initiatives intended to address seismic activity in Oklahoma and elsewhere could increase our costs of compliance or lead to operational delays, which could have a material adverse effect on our business, results of operations or financial condition. We dispose of large volumes of water produced alongside oil and natural gas "produced water" in connection with our drilling and production operations, pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued under existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

There exists a growing concern that the injection of produced water into belowground disposal wells triggers seismic events in certain areas, including Oklahoma and Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting and operating of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma has taken numerous regulatory actions in response to concerns related to the operation of produced water disposal wells and induced seismicity. Oklahoma has adopted a "traffic light" system, wherein the Oklahoma Corporation Commission (OCC) reviews new or existing disposal wells for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. In September 2014, the OCC adopted rules for operators of produced water disposal wells in certain seismically-active areas, or Areas of Interest, requiring operators to monitor and record well pressure and injected volume on a daily basis and further requiring operators of wells permitted for disposal of 20,000 barrels per day or more of produced water to conduct more frequent mechanical integrity testing. On March 25, 2015, the Oklahoma Corporation Commission's Oil and Gas Conservation Division (OGCD) issued a directive, expanding the Areas of Interest for induced seismicity. Under the new directive, operators of 347 disposal wells located within the expanded Areas of Interest of the Arbuckle formation were given until April 2015 to demonstrate that their wells were not disposing into or in communication with the crystalline basement rock. Operators of wells in contact or communication with the basement rock were required to reduce the depth of, or "plug back," those wells or, alternatively, to reduce disposal volume by 50 percent. On July 17, 2015, the OGCD issued another directive, further expanding the covered area to include an additional 211 disposal wells. Under this second directive, operators were given until August 2015 to prove that they were not injecting below the Arbuckle formation or, as necessary, to plug back those wells in contact or communication with the crystalline basement rock, without the option of reducing disposal volume by 50 percent. The OGCD imposed further reductions on oil and natural gas wastewater disposal well volume in a prescribed area of northern Oklahoma County and southern Logan County in August 2015, requiring operators to reduce disposal volumes for affected wells by approximately 38 percent below 2014 reported volumes, within a specified 60-day period. OGCD imposed additional restrictions on wells in Fairview County in January 2016, requiring that all disposal wells located within 3.5 miles of a seismic event's epicenter reduce injection volumes by 50 percent and 25 percent for wells within 10 miles of the event's epicenter. The OGCD has also begun imposing additional testing requirements on wells located within 15 miles of an event's epicenter. Additional regulatory action in this area is likely, and the Oklahoma legislature has introduced new legislation to expand the OCC's authority to address concerns related to disposal wells and induced seismicity. Furthermore, following increased seismic activity in

February 2016, the OGCD released a wastewater volume reduction plan. The plan calls for the operators of over 240 injection wells to reduce underground wastewater injections. The plan covers more than 5,200 square miles in northwest Oklahoma, which is near our operations, and seeks reductions of more than 500,000 barrels of wastewater per day. Implementation of the plan will be phased in over the next two months.

In Texas, in 2014, the Texas Railroad Commission (TRC) published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If a permittee or a prospective permittee fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

Restriction on the volumes permissible for injection or a lack of alternative waste disposal sites could cause us to delay, curtail or discontinue our exploration and development plans. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, such as mandated produced water recycling in some portion or all of our operations, may reduce our profitability. These developments may result in additional levels of regulation, or increased complexity and costs with respect to existing regulations, that could lead to operational delays or increased operating and compliance costs, which could have a material adverse effect on our business, results of operations, cash flows or financial condition.

Our use of oil and natural gas price derivative contracts may limit future revenues and cash flows from price increases and involves the risk that our counterparties may be unable to satisfy their obligations to us and any inability to maintain our current derivative positions in the future specifically could result in financial losses or could reduce our income. 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, 2015, we had no outstanding derivative contracts related to our NGL production. A significant portion of our oil derivative contracts include sold 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, 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. 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.

Additionally, in the current commodity price environment, we have concluded that utilizing derivative contracts to lock in historically low prices for oil and natural gas for some of our anticipated future production is not in the best interest of the Company and may continue to hold that conclusion in the future. As a result, as of year-end 2015, a meaningful portion of our expected oil production for 2016 and beyond remained, and may continue to remain, unhedged and subject to fluctuating market prices. If we are ultimately unable to, or choose not to, hedge additional expected oil production volumes for 2016 and beyond, we will be subject to further potential commodity price volatility, which may result in lower than expected cash flows and revenues.

Our limited ability to hedge our NGL production and commodity basis differentials could adversely impact our cash flows from operations. A liquid, readily available and commercially viable market for hedging NGL and commodity basis differentials has not developed in the same way that exists for oil and natural gas priced at WTI and Henry Hub, respectively. The current direct NGL and commodity basis differential hedging market is constrained in terms of price, volume, duration and number of counterparties. This limits both our ability to hedge our NGL production and price difference based on point of sale effectively or at all. As a result, currently, we directly hedge only our oil and natural gas production priced at WTI and Henry

Hub, respectively. If the current price levels for NGL continue or decrease in the future or the commodity basis differentials versus WTI or Henry Hub negatively increase, our cash flows from operations would be affected.

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. Although we have reduced our capital expenditures in 2016 to more closely align with our projected cash flows, we anticipate that our 2016 capital investment levels may exceed our projected cash flows from operations in 2016. As a result, we may borrow additional funds under our credit facility, due in part to our decision to continue certain portions of our drilling program in order to avoid future lease renewals to retain certain acreage. If necessary, we may sell non-strategic assets or potentially access public debt and/or equity markets 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 oil, natural gas and NGLs; production costs; availability of economical gathering, processing, storage and transportation in our operating areas; 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, unbudgeted acquisitions 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 changes in drilling plans. Alternatively, we may have to reduce capital expenditures, and our ability to execute our business plans could be adversely affected, if:

- we generate less operational cash flow than we anticipate;
- we are unable to sell non-strategic assets at acceptable prices due to low commodity prices;
- our customers or working interest owners default on their obligations to us;
- 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 oil and gas companies; or
- we are unable to access the capital markets at a time when we would like, or need, to raise capital.

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, 2015, we had total indebtedness of $2.5 billion, including $39 million in borrowings under our 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 and any future agreements governing our other indebtedness and financial obligations 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.

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.

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.

Actual quantities of oil, natural gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates. Estimating quantities of oil, natural gas and NGL reserves 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.

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.

In accordance with SEC requirements, we calculate the estimated discounted future net cash flows from proved reserves using the SEC's pricing methodology for calculating proved reserves, 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. You should not assume that the present value of future net cash flows is the current market value of our proved reserves.

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 oil, natural gas and NGL production and lower revenues and cash flows from operations. Future oil, natural gas and NGL 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 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 at December 31, 2015, the ceiling value of our reserves was calculated based upon SEC pricing of $2.59 per MMBtu for natural gas and $50.11 per barrel for oil. Using these prices, our ceiling for the U.S. did not exceed the net capitalized costs of oil and gas properties resulting in a ceiling test writedown. For the twelve months ended December 31, 2015, we recorded U.S. ceiling test writedowns of approximately $4.8 billion ($3.3 billion after tax). Using SEC pricing, our ceiling for China at December 31, 2015 did not exceed the net capitalized costs of oil and gas properties, resulting in a ceiling test writedown. For the twelve months ended December 31, 2015, we recorded China ceiling test writedowns of approximately $118 million ($60 million after tax). 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 2016 could exceed $500 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 for a prolonged period of time. 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 costly and 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:

- increases in the costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- decreases in oil, natural gas and NGLs prices;
- limited availability to us of financing on acceptable terms;
- adverse weather conditions and changes in weather patterns;
- unexpected operational events and drilling conditions;
- abnormal pressure or irregularities in geologic formations;
- surface access restrictions;
- access to, and costs for, water needed in our waterflood project in the Greater Monument Butte Unit (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 oil, natural gas, and NGLs; 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, cash flows 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;
- pipe or cement failures and casing collapses;
- pipeline or other facility ruptures and spills;
- equipment malfunctions or operator error;
- discharges of toxic gases;
- 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 and cash flows 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, natural resources and equipment;
- 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 and remediation costs 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.

In addition, our hydraulic fracturing operations require significant quantities of water. Regions in which we operate have recently experienced drought conditions. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs.

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 cash flows and the funds available to us for our exploration, development and production activities and could, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flows. See also "— We may not be insured against all of the operating risks to which our business is exposed."

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including oil, natural gas and NGL prices, the availability of capital, costs, drilling results, regulatory approvals, available transportation capacity, and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce crude oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified. Currently low oil prices, reduced capital spending and numerous other factors, many of which are beyond our control, could result in our failure to establish production on undeveloped acreage, and, if we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 64% of our total net undeveloped acreage at December 31, 2015. At that date, we had leases representing approximately 94,000 net undeveloped acres expiring in 2016, approximately 157,000 net undeveloped acres expiring in 2017, and approximately 97,000 net undeveloped acres expiring in 2018. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our proved undeveloped reserves may not be ultimately developed or produced. The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. At December 31, 2015, approximately 35% of our total estimated proved reserves (by volume) were undeveloped and may not be ultimately developed or produced. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve estimates assume we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove to be accurate. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled, or that the results of such development will be as estimated. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC's reserve rules, because proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any proved undeveloped reserves that are not developed within this five-year time frame. A removal of such reserves could adversely affect our business.

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.

At the federal level, the EPA has issued final federal Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed in April 2015 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants; and issued in May 2014 an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Also, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including, for example, notice to and pre approval by BLM of the proposed hydraulic fracturing activities; development and pre approval by BLM of a plan for managing and containing flowback fluids and produced water recovered during the hydraulic fracturing process; implementation of measures designed to protect usable water from hydraulic fracturing activities; and public disclosure of the chemicals used in the hydraulic fracturing fluid. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision is pending, however. In addition, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. The adoption of new federal rules or regulations relating to hydraulic fracturing could lead to increased operating costs, delays and curtailment in the pursuit of exploration, development or production activities, which in turn could materially adversely affect our operations.

Several governmental reviews are underway that focus on environmental aspects of hydraulic fracturing activities. In June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. The draft report is expected to be finalized after a public comment period and a formal review by EPA's Science Advisory Board. In addition, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing.

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.

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. Furthermore, future environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could cause delays, interruptions or termination of operations, which may result in increased operating costs and have an effect on our business, results of operations, cash flows or financial condition.

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 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, natural resource protection, and other governmental regulations. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (NAAQS) for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. 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:

- restrictions for the protection of wildlife that regulate the time, place and manner in which we conduct operations;
- 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.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials into the environment, 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 or limit or even 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.

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 results of operations and cash flows, in addition to the demand for the oil, natural gas and NGLs that we produce.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects. In response to findings that emissions of carbon dioxide, methane and other "greenhouse gases," (GHGs), present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration

(PSD) pre-construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. More recently, in December 2015, the EPA finalized rules added new sources to the scope of the GHG monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers of hydraulically fractured wells. The revisions also include the addition of well identification reporting requirements for certain facilities. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs. Also, in August 2015, the EPA announced proposed rules that would establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, as part of an overall effort to reduce methane emissions by up to 45 percent in 2025. The BLM proposed similar regulations designed to reduce methane emissions for oil and gas activities on federal lands in January 2016 that seek to impose limits on venting and flaring and would require enhanced leak detection and repair programs. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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.

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. To date, the CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet required the clearing of any other classes of swaps, including commodity swaps. Although we expect to qualify for the end-user exception from the clearing requirement for our swaps entered into to hedge our commercial risks, the application of the mandatory clearing requirements to other market participants, such as swap dealers, along with changes to the markets for swaps as a result of the trade execution requirement, may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap execution facility. In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce our liquidity and cash available for capital expenditures and could reduce our ability to manage commodity price volatility and the volatility in our cash flows. 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 those derivative instruments that we use. 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.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent Newfield transacts with counterparties in foreign jurisdictions, it may become subject to such regulations. At this time, the impact of such regulations is not clear.

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.

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction. Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes could include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and natural 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.

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 this legislation or any other similar changes in U.S. federal and state income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development and any such change could negatively affect our financial condition and results of operations. Additionally, legislation could be enacted that increases the taxes states impose on oil and natural gas extraction. Moreover, the President of the United States has proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an "oil fee" of $10.25 on a per barrel equivalent of crude oil. This fee would be collected on domestically produced and imported products. The fee would be phased in evenly over five years, beginning October 1, 2016. The adoption of this, or similar proposals, could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil.

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, exchange rate fluctuations, or other activities that disrupt markets and restrict payments or the movement of funds;

- 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;
- taxation policies, including increases in taxes and governmental royalties, retroactive tax claims and investment restrictions;
- 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.

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 results of operations. 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. In the past, competition for these professionals was strong, and in a price recovery environment may be strong again, which could result in future retention and attraction issues.

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, cash flows 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 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 oil and gas 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.

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 oil and gas 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, cash flows 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 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 significant 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. See for example "— We may be responsible for decommissioning liabilities for offshore interest we no longer own." Generally, 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.

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 us. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to affect a change of control, to acquire us or to replace incumbent management, including, for example, limitations on shareholders' ability to remove directors, call special meetings and to propose and nominate directors or otherwise propose actions for approval at stockholder meetings, as well as the ability of our board of directors to amend our certificate of incorporation and bylaws and to issue and set the terms of preferred stock without the approval of our stockholders. In addition, our change of control severance plan, change of control severance agreements with certain officers and our omnibus stock plans and deferred compensation plan contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of equity awards and acceleration of deferred compensation, 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 us.
Delays in obtaining licenses, permits, and other government authorizations required to conduct our operations could adversely affect our business. Our operations require licenses, permits, and in some cases renewals of licenses and permits from various governmental authorities. Our ability to obtain, sustain or renew such licenses and permits on acceptable terms is subject to changes in regulations and policies and to the discretion of the applicable government agencies, among other factors.

Our inability to obtain, or our loss of or denial of extension, to any of these licenses or permits could hamper our ability to produce revenues or cash flows from our operations.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

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 evaluated the discharges and our proposed restoration and mitigation, and a negotiated settlement was 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 was paid in 2015 and the remediation and mitigation work was completed in 2015. This administrative settlement did not 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.

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 federal government 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 19, 2016) 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	54	President, Chief Executive Officer and Chairman of the Board	16
Lawrence S. Massaro	52	Executive Vice President and Chief Financial Officer	5
Gary D. Packer	53	Executive Vice President and Chief Operating Officer	20
George T. Dunn	58	Senior Vice President — Development	23
John H. Jasek	46	Senior Vice President — Operations	16
Stephen C. Campbell	47	Vice President — Investor Relations	16
George W. Fairchild, Jr.	48	Chief Accounting Officer	4
Timothy D. Yang	43	General Counsel and Corporate Secretary	1
Valerie A. Mitchell	44	Vice President — Mid-Continent	11
Matthew R. Vezza	42	Vice President — Western Region	3

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. 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. He previously managed our Gulf of Mexico operations from March 2005 until October 2007, and was promoted from General Manager to Vice President — Gulf of Mexico 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 in November 2013. Mr. Fairchild joined Newfield in August of 2012 as Controller 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.

Timothy D. Yang joined Newfield as General Counsel and Corporate Secretary in July 2015. Prior to joining Newfield, Mr. Yang served as Senior Vice President, Land & Legal, General Counsel, Chief Compliance Officer and Secretary of Sabine Oil & Gas Corporation from December 2014 to July 2015. Mr. Yang was previously promoted to Senior Vice President, General Counsel, Chief Compliance Officer and Secretary in February 2013 after beginning service at Sabine in 2011 as Vice President, General Counsel and Secretary. Prior to Sabine, Mr. Yang served as Associate General Counsel and Assistant Corporate Secretary for Eagle Rock Energy Partners, L.P. from 2009 to 2011. His legal experience covers both public and private companies within the energy and investment industries including Invesco Ltd./AIM Investments, Pogo Producing Company and AEI Services LLC. Mr. Yang holds a Bachelor of Arts in Biology from Trinity University, obtained his Juris Doctor from the University of Houston Law Center and is a member of the Texas and Kansas state bar associations.

Valerie A. Mitchell was promoted to Vice President — Mid-Continent in February 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 The Coastal Corporation and El Paso Corporation. 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 — Western Region in August of 2015 when the Company's Onshore Gulf Coast and Rocky Mountain business units were combined after serving as Vice President — Rocky Mountains beginning 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
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	$36.26	$22.31
Second Quarter	40.27	33.96
Third Quarter	36.77	26.78
Fourth Quarter	41.34	29.88
2016:		
First Quarter (through February 19, 2016)	$33.01	$20.84

On February 19, 2016, the last reported sales price of our common stock on the NYSE was $22.31. As of that date, there were approximately 1,482 record 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 5¾% Senior Notes due 2022, our 5 % Senior Notes due 2024 and our 5 % Senior Notes due 2026 could restrict our ability to pay cash dividends. See "Contractual Obligations" under Item 7 of this report and Note 10, "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, 2015.

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, 2015	7,304	$33.77	—	—
November 1 — November 30, 2015	7,514	40.26	—	—
December 1 — December 31, 2015	4,781	37.00	—	—
Total	19,599	$37.05	—	—

(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 (PHLX SIG) and our peer group on December 31, 2010 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 Bill Barrett Corporation, Carrizo Oil & Gas, Inc., Concho Resources Inc., Chesapeake Energy Corporation, Cimarex Energy Co., Continental Resources Inc., Devon Energy Corporation, Energen Corp., EP Energy Corp., Jones Energy, Marathon Oil Corporation, Matador Resources Company, Noble Energy, Inc., PDC Energy, Pioneer Natural Resources Company, QEP Resources Inc., SM Energy Co., Whiting Petroleum Corporation and WPX Energy Inc.

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

Comparison of Five-Year Cumulative Total Return

Total Return Analysis	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015
Newfield Exploration Company	$ 100.00	$ 52.32	$ 37.14	$ 34.16	$ 37.61	$ 45.15
S&P 500 Index - Total Returns	100.00	102.11	118.45	156.82	178.28	180.75
PHLX SIG Oil Exploration & Production Index	100.00	90.94	84.64	107.12	76.81	42.18
New Peer Group	100.00	99.53	95.49	134.62	107.05	66.51
Prior Peer Group	100.00	93.94	90.35	129.72	87.17	51.55

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,				
	2015	2014	2013	2012	2011
	(In millions, except per share data)				
Statement of Operations Data:					
Oil, gas and NGL revenues[(1)]	$1,557	$2,288	$1,857	$1,562	$1,824
Income (loss) from continuing operations	(3,362)	650	73	(922)	427
Net income (loss)	(3,362)	900	147	(1,184)	539
Earnings (loss) per share:					
Diluted:					
Income (loss) from continuing operations	$(21.18)	$4.71	$0.39	$(6.85)	$3.16
Diluted earnings (loss) per share	(21.18)	6.52	0.94	(8.80)	3.99
Weighted-average number of shares outstanding for diluted earnings (loss) per share	159	138	136	135	135
Balance Sheet Data (at end of period):					
Total assets	$4,768	$9,580	$9,297	$7,884	$8,968
Long-term debt	2,467	2,874	3,670	3,017	2,983

(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 operations are focused primarily on large scale, onshore liquids-rich resource plays in the United States. Our principal areas of operation are the Anadarko and Arkoma Basins of Oklahoma, the Williston Basin of North Dakota, the Uinta Basin of Utah and the Maverick and Gulf Coast basins of Texas. In addition, we have oil developments offshore 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 investments;
- 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 over the last year and remain low into the first quarter of 2016. Nevertheless, we had many operational, financial and strategic successes in 2015.

Significant 2015 highlights include:

- domestic production increased 6% over 2014 to 49.3 MMBOE, excluding approximately 7.7 Bcf of natural gas produced and consumed in operations;
- domestic liquids production up 12% over 2014;
- net acres in SCOOP and STACK were approximately 315,000 acres;
- lease operating expense for continuing operations, on a per BOE basis, decreased 21% year-over-year;
- general and administrative expense for continuing operations, on a per BOE basis, decreased 6% year-over-year, despite approximately $40 million of one-time costs related to the reduction of our workforce and domestic restructuring costs incurred during the year;
- net derivative asset of $367 million at December 31, 2015, $271 million of which relates to 2016 production;
- 25.3 million additional shares of common stock issued through a public equity offering, for net proceeds of approximately $815 million, which were used primarily to repay all borrowings under our credit facility and money market lines of credit;
- net proceeds from new debt issued through a public debt offering were used to redeem existing debt with a higher interest rate;
- credit facility amended to increase the borrowing capacity by $400 million to $1.8 billion and extend the maturity date two years to 2020; and
- domestic business restructured to better utilize resources and improve cost efficiencies.

We have adapted our 2016 business plan in response to the continuation of low commodity prices:

- maintain and prioritize liquidity preservation over reserve and production growth;
- better align capital investments with cash flows from operations;
- allocate the majority of capital to SCOOP and STACK; and

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• implement a plan to further reduce domestic per unit lease operating costs.

While we expect to achieve savings from cost reductions during 2016, given the lower oil and natural gas price environment as compared to 2015, our revenues are expected to be significantly lower in 2016 as compared to 2015.

Results of Continuing Operations

Our continuing operations consist of exploration, development and production activities in the United States and China.

Domestic Revenues and Production. Revenues from domestic operations of $1.3 billion for the year ended December 31, 2015 were 42% lower than 2014. The lower revenues were attributable to a 46% decrease in the average revenue per BOE compared to 2014. Domestic liquids production increased 12% year over year, reducing the impact of lower commodity prices by $236 million.

Our 2015 domestic crude oil production increased 15%, primarily due to doubling our Anadarko Basin oil volumes from 2014 levels. Additionally, Williston Basin and Eagle Ford each experienced year over year oil production increases of 3%. Domestic NGL production increased 4%, while natural gas production decreased 2% from 2014 levels. Adjusted for the sale of Granite Wash assets in the third quarter of 2014 (as discussed in Note 6, "Oil and Gas Properties and Other Property and Equipment," to the consolidated financial statements contained in Item 8 of this report), NGL and natural gas production increased 16% and 8%, respectively. NGL production volumes increased in the Anadarko Basin and Williston Basin by 20% and 40%, respectively. Natural gas production in the Anadarko Basin and Williston Basin increased 42% and 20%, respectively.

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 primarily due to production increases in our Anadarko, Williston and Uinta Basins of 103%, 46% and 15% 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 Anadarko Basin, Eagle Ford and Williston Basin of 147%, 63% and 55%, respectively, during the year ended December 31, 2014 generated approximately 25% 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.

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.

China Revenues and Production/Liftings. Our revenues from China were $262 million for the year ended December 31, 2015. Approximately 85% of our 2015 production from China was from the Pearl development, which achieved first oil in the fourth quarter of 2014.

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. Production from China decreased 25% compared to the same period in 2013 primarily due to the temporary shut-in. Production resumed in August 2014; however, we had not accumulated sufficient quantities to schedule a lifting during the remainder of 2014. Liftings from Bohai Bay resumed 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.

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

	2015	2014	2013
Production/Liftings:			
Domestic:(1)			
Crude oil and condensate (MBbls)	21,346	18,547	14,200
Natural gas (Bcf)	116.3	118.2	116.1
NGLs (MBbls)	8,553	8,207	5,163
Total (MBOE)	49,277	46,448	38,706
China:(2)			
Crude oil and condensate (MBbls)	5,399	499	668
Total continuing operations:			
Crude oil and condensate (MBbls)	26,745	19,046	14,868
Natural gas (Bcf)	116.3	118.2	116.1
NGLs (MBbls)	8,553	8,207	5,163
Total (MBOE)	54,676	46,946	39,374
Average Realized Prices:			
Domestic:(3)			
Crude oil and condensate (per Bbl)	$39.89	$80.40	$86.21
Natural gas (per Mcf)	2.40	4.11	3.39
NGLs (per Bbl)	18.40	32.04	30.74
Crude oil equivalent (per BOE)	26.28	48.41	45.91
China:			
Crude oil and condensate (per Bbl)	$48.50	$78.52	$103.19
Total continuing operations:			
Crude oil and condensate (per Bbl)	$41.63	$80.35	$86.97
Natural gas (per Mcf)	2.40	4.11	3.39
NGLs (per Bbl)	18.40	32.04	30.74
Crude oil equivalent (per BOE)	28.48	48.73	46.88

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(1) Excludes natural gas produced and consumed in operations of 7.7 Bcf in 2015, 8.5 Bcf in 2014 and 8.1 Bcf in 2013.

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

(3) Had we included the realized effects of derivative contracts, the domestic average realized prices would have been as follows:

	2015	2014	2013
Crude oil and condensate (per Bbl)	$57.48	$80.23	$85.77
Natural gas (per Mcf)	3.51	3.81	3.97

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Operating Expenses.

Year ended December 31, 2015 compared to December 31, 2014

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)
	2015	2014		2015	2014	
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$4.69	$6.44	(27)%	$231	$299	(23)%
Transportation and processing	4.29	3.74	15%	212	174	22%
Production and other taxes	0.91	2.26	(60)%	45	105	(57)%
Depreciation, depletion and amortization	15.31	18.46	(17)%	754	857	(12)%
General and administrative	4.80	4.78	—%	237	221	7%
Ceiling test and other impairments	97.13	—	100%	4,786	—	100%
Other	0.19	0.53	(64)%	9	25	(63)%
Total operating expenses	127.32	36.21	>100%	6,274	1,681	>100%
China:						
Lease operating	$10.07	$24.05	(58)%	$54	$12	>100%
Production and other taxes	0.15	11.20	(99)%	1	6	(85)%
Depreciation, depletion and amortization	30.09	25.87	16%	163	13	>100%
General and administrative	1.31	1.11	18%	7	1	>100%
Ceiling test impairment	21.84	—	100%	118	—	100%
Other	0.21	—	100%	1	—	100%
Total operating expenses	63.67	62.23	2%	344	32	>100%
Total Continuing Operations:						
Lease operating	$5.22	$6.62	(21)%	$285	$311	(8)%
Transportation and processing	3.87	3.70	5%	212	174	22%
Production and other taxes	0.84	2.36	(64)%	46	111	(59)%
Depreciation, depletion and amortization	16.77	18.53	(9)%	917	870	5%
General and administrative	4.46	4.74	(6)%	244	222	9%
Ceiling test and other impairments	89.69	—	100%	4,904	—	100%
Other	0.19	0.53	(64)%	10	25	(58)%
Total operating expenses	121.04	36.48	>100%	6,618	1,713	>100%

Domestic Operations. For the year ended December 31, 2015, total operating expenses per BOE for domestic operations increased significantly compared to the year ended December 31, 2014 due to the impact of ceiling test impairments of $4.8 billion. Excluding these ceiling test impairments and depreciation, depletion and amortization, which was lower in 2015 due to the ceiling test impairments, domestic operating expenses per BOE decreased 16% from 2014 for the following primary reasons:

- Lease operating expenses (LOE) decreased 27% on a per BOE basis primarily due to lower service costs and higher production volumes. Service costs declined primarily in the Uinta and Anadarko basins period over period due to our increased focus on cost-reduction initiatives combined with downward service cost pressures in the industry due to lower oil and natural gas prices.

- Transportation and processing expense increased 15% on a per BOE basis primarily due to the increase in combined gas and NGL volumes in SCOOP and STACK, which are subject to higher processing fees related to liquids-rich gas production.
- Production and other taxes on a per BOE basis decreased 60% year-over-year primarily due to lower revenues, and a higher percent of our 2015 production derived from areas with lower production tax rates. Additional decreases were due to enhanced recovery credits and tax incentives for stripper wells for our Uinta Basin assets, which includes $7 million of credits that relates to prior years (see "Reclassifications and Out-of-Period Adjustments" in Note 1 to our consolidated financial statements in Item 8 of this report). Excluding the impact of these additional tax incentive recoveries, production and other taxes as a percent of total revenue were 4.0% and 4.7% for the years ended December 31, 2015 and 2014, respectively.
- Depreciation, depletion and amortization (DD&A) decreased 17% on a per BOE basis primarily due to the impact of $4.8 billion non-cash ceiling test impairments recorded in 2015. We expect a further decrease in the first quarter of 2016 as a result of the impairment recorded effective December 31, 2015.
- General and administrative expense (G&A) increased 7% primarily as a result of reduced capitalization of direct internal costs, workforce reductions, organization restructuring and stock-based compensation programs. Excluding these items that affect comparability, gross G&A costs decreased 15% year-over-year primarily due to cost savings initiatives including a more than 20% reduction of our workforce. The following table presents information regarding G&A expenses for our domestic operations:

	Unit-of-Production Year Ended December 31,		Percentage Increase (Decrease)	Total Amount Year Ended December 31,		Percentage Increase (Decrease)
	2015	2014		2015	2014	
	(Per BOE)			(In millions)		
G&A expense (net of amounts capitalized)	$4.80	$4.78	— %	$237	$221	7 %
Capitalized direct internal costs(1)	1.52	2.90	(48)%	75	135	(45)%
Gross G&A expense	6.32	7.68	(18)%	312	356	(13)%
Other items:						
Reduction in workforce and restructuring(2)	(0.77)	—	(100)%	(39)	—	(100)%
SVAP program(3)	0.05	(0.71)	>100%	3	(33)	>100%
Total	5.60	6.97	(20)%	276	323	(15)%

(1) Capitalized direct internal costs decrease is consistent with the reduced exploration and development activities in the Uinta, Williston and Maverick basins during 2015.

(2) Includes severance costs for workforce reductions in early 2015, as well as office-lease abandonment and other organizational restructuring costs related to the consolidation of our Denver and Houston offices in 2015.

(3) SVAP Program decrease is associated with the decrease in the estimated fair value of the liability for our Stockholder Value Appreciation Program (SVAP), which ended December 31, 2015. During 2014, three thresholds were achieved that resulted in payments to employees.

- During 2015, we recorded non-cash ceiling test impairments of $4.8 billion due to a net decrease in the discounted value of our proved reserves. The decrease primarily resulted from a 47% decrease in crude oil SEC pricing and a 40% decrease in natural gas SEC pricing since December 31, 2014. These commodity price decreases were partially offset by the impact of current service cost reductions on our cash flow estimates. Additionally during the first quarter of 2015, we recorded a $4 million rig impairment associated with our decision to indefinitely lay down both of our company-owned drilling rigs in the Uinta Basin.
- Other operating expense decreased $16 million primarily due to equipment inventory impairments and legal settlements recorded in 2014.

China Operations. For the year ended December 31, 2015, total operating expenses increased $312 million compared to the year ended December 31, 2014, primarily due to a full year of production activity from our Pearl development and the ceiling test impairments recorded in the third and fourth quarters of 2015. As a result of the different cost structures of our Pearl development and our Bohai Bay field, the 2015 results are not comparable with 2014. The 2015 increase was slightly offset by a $5 million decrease in production and other taxes. A new regulation was implemented by the Chinese government in early 2015 resulting in no special levy taxes on production with an actual realized contract price below $65 per barrel. As such, until our contract prices exceed $65 per barrel, we will continue to experience lower production and other taxes in China.

The Pearl development produced at a rate of 13,000 BOEPD (net) from five horizontal wells and one vertical well during the fourth quarter of 2015.

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

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)
	2014	2013		2014	2013	
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$6.44	$6.85	(6)%	$299	$266	13%
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	0.53	0.34	56%	25	13	90%
Total operating expenses	36.21	35.38	2%	1,681	1,370	23%
China:						
Lease operating	$24.05	$11.99	>100%	$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	$6.62	$6.94	(5)%	$311	$274	14%
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	0.53	0.33	61%	25	13	89%
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:

- Lease operating expenses decreased 6% 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, Arkoma and Eagle Ford plays.

- Transportation and processing expense increased 6% on a per BOE basis primarily due to a 59% increase in NGL volumes processed during 2014.

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- Production and other taxes as a percent of revenue increased 1%. Approximately one-half of this increase was the result of higher tax incentives as well as an ad valorem tax adjustment in 2013. The remaining increase, on a percent of revenue basis, was 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 was driven by increased liquids production as a percent of total production and the associated increase in average revenue per BOE from $45.91 for the year ended December 31, 2013 to $48.41 for the year ended December 31, 2014.
- Depreciation, depletion and amortization 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 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 14, "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 deepwater operations for our Pearl development. 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.

Interest Expense. The following table presents information about interest expense for each of the years ended December 31. Interest expense associated with unproved oil and gas properties is capitalized into oil and gas properties.

	2015	2014	2013
	(In millions)		
Gross interest expense:			
Credit arrangements	$10	$10	$11
Senior notes	132	101	101
Senior subordinated notes	21	89	93
Other	1	—	—
Total gross interest expense	164	200	205
Capitalized interest	(33)	(53)	(53)
Net interest expense	$131	$147	$152

Gross interest expense decreased in 2015 as compared to 2014 due to the redemption of our 7 % Senior Subordinated Notes due 2018 in the fourth quarter of 2014 and the redemption of our 6 % Senior Subordinated Notes due 2020 in April 2015. This decrease was partially offset by the additional interest expense associated with our $700 million 5 % Senior Notes due 2026 issued in March 2015. Gross interest expense decreased slightly in 2014 as compared to 2013 due to the redemption of our 7 % Senior Subordinated Notes due 2018 in the fourth quarter of 2014. See Note 10, “Debt,” to our consolidated financial statements in Item 8 of this report.

Capitalized interest decreased in 2015 as compared to 2014 due to a reduction of the average amount of unproved oil and gas properties coupled with a reduced capitalization rate due to a reduction in our average borrowing rate. The average balance of unproved oil and gas properties was consistent for the first three quarters of 2014 resulting in a relatively flat capitalized interest in 2014 as compared to 2013.

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. The $259 million gain recognized in “Commodity derivative income (expense)” in our consolidated statement of operations related to our derivative financial instruments is comprised of a $505 million realized gain and a $246 million unrealized loss. The amount of unrealized gain (loss) on derivatives is the result of the change in the total fair value of our derivative positions from the prior year. The components of the change in the fair value of our net derivative asset (liability) follows:

	Positions Settled in 2015	Positions Settling in 2016 and Thereafter	Total
	(In millions)		
Net derivative asset at December 31, 2014	$423	$190	$613
Settled positions[1]	(423)	—	(423)
Change in fair value of remaining positions	—	177	177
Total unrealized gain (loss)	(423)	177	(246)
Net derivative asset (liability) at December 31, 2015	$—	$367	$367

(1) Represents the fair value included in the net derivative asset as of December 31, 2014 that have settled during 2015. Actual settlement amounts differ due to the changes in the fair value of the positions between the balance sheet date and the settlement date and are reflected in the realized gain (loss) noted in Note 4, "Derivative Financial Instruments".

Taxes. The effective tax rates for continuing operations for the years ended December 31, 2015, 2014 and 2013 were 32%, 37% and 64%, respectively. Our effective tax rate for all periods was different than the federal statutory rate of 35% due to the change in valuation allowances, 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 in both the U.S and China. Our future effective tax rates may also be impacted by additional ceiling test writedowns or other items which generate deferred tax assets, deferred tax asset valuation allowances, and/or reversal of such valuation allowances. The following table summarizes our tax activity that derives our 2015 effective tax rate.

	Domestic	China	Total
		(In millions)	
Total income (loss) before income taxes	$(4,865)	$(82)	$(4,947)
U.S. federal statutory tax rate	35%	35%	35%
Tax expense at statutory tax rate	(1,703)	(29)	(1,732)
State and local income taxes, net of tax effect	(45)	—	(45)
Change in valuation allowances	202	13	215
Foreign tax on foreign earnings	—	(21)	(21)
Other	(2)	—	(2)
Total provision (benefit) for income taxes	$(1,548)	$(37)	$(1,585)
Effective tax rate	32%	45%	32%

See Note 7, "Income Taxes" to our consolidated financial statements in Item 8 of this report for additional disclosures.

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Results of Discontinued Operations - Malaysia

During the second quarter of 2013, our business in Malaysia met the criteria for classification 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 19, "Discontinued Operations," to our consolidated financial statements in Item 8 of this report for additional information regarding the sale of our Malaysia business.

Revenues and Liftings. Our 2014 and 2013 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 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.

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. The average realized price per BOE remained essentially flat for 2013 and through the close date of the sale in 2014.

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

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

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

Operating Expenses. The following table presents our total operating expenses for discontinued operations for 2014, which decreased 89% compared to the same period of 2013 as a result of the sale of our Malaysia business in February 2014.

	Unit-of-Production Year Ended December 31, 2014	2013	Percentage Increase (Decrease)	Total Amount Year Ended December 31, 2014	2013	Percentage Increase (Decrease)
	(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)%

Liquidity and Capital Resources

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

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.

In response to future uncertainty regarding the timing and magnitude of an eventual recovery of crude oil and natural gas prices, which have declined significantly since the fourth quarter of 2014, our capital spending for 2015 was reduced 26% from 2014 levels to reduce deficit spending and preserve long-term liquidity. During 2015, as part of our strategy to optimize long-term liquidity, we:

- issued 25.3 million additional shares of common stock through a public equity offering and received net proceeds of approximately $815 million in the first quarter of 2015, which were used primarily to repay all borrowings under our credit facility and money market lines of credit;
- issued $700 million 5 % Senior Notes due 2026 through a public debt offering and received net proceeds of $691 million in March 2015. In April 2015, we used these proceeds and cash on hand to redeem the $700 million aggregate principal of our 6 % Senior Subordinated Notes due 2020; and
- amended our credit facility in March 2015 to increase the borrowing capacity from $1.4 billion to $1.8 billion and extend the maturity date from June 2018 to June 2020.

We expect our 2016 budget will be financed through our cash flows from operations, borrowings under our credit facility, selling non-strategic assets or potentially accessing the public debt and equity markets. Our 2016 capital budget, excluding estimated capitalized interest and direct internal costs of approximately $100 million, is expected to be approximately $625-$675 million.

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, and our ability to fund them, 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 2016 operations and continue to meet our other obligations. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Arrangements and Other Financing Activities. In March 2015, we entered into the fourth amendment to our Credit Agreement. This amendment extended the maturity date of the revolving credit facility from June 2018 to June 2020 and increased the borrowing capacity from $1.4 billion to $1.8 billion. We incurred $7 million of financing costs related to this amendment, which will be amortized through June 2020. We also maintain money market lines of credit of $195 million. At December 31, 2015, we had $39 million in borrowings under our money market lines of credit, no borrowings outstanding under our revolving credit facility and no letters of credit outstanding under our credit facility.

In April 2015, we completed the redemption of our $700 million aggregate principal of 6 % Senior Subordinated Notes due 2020. The transaction included a premium payment of approximately $24 million. At December 31, 2015, we had no scheduled maturities of senior notes until 2022. For a more detailed description of the terms of our credit arrangements and senior notes, please see Note 10, “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 (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns and goodwill impairments) to interest expense of at least 3.0 to 1.0. At December 31, 2015, we were in compliance with all of our debt covenants under our credit facility and do not foresee this changing in 2016.

As of February 19, 2016, we had $90 million outstanding under our money market lines of credit and $80 million outstanding under our revolving credit facility.

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, 2015 and 2014, we had negative working capital of $22 million and $161 million, respectively.

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

Our net cash flows provided by operations were approximately $1.2 billion in 2015, $1.4 billion in 2014 (includes $3 million of cash flows provided by our Malaysia discontinued operations) and $1.4 billion in 2013 (includes $249 million of cash flows provided by our Malaysia discontinued operations). We had no cash flows provided by discontinued operations in 2015. The primary driver of lower operating cash flows in 2015 was lower revenues as a result of lower commodity prices, which we expect to continue in 2016.

Cash Flows from Investing Activities. Net cash used in investing activities for 2015 was $1.6 billion compared to $660 million for 2014. The increase in net cash used in 2015 investing activities was primarily due to net proceeds of $1.4 billion received in 2014 from the sale of our Malaysia business and Granite Wash assets. Cash used for capital expenditures in 2015 was approximately $457 million lower due to our planned reductions in capital spending as compared to 2014.

Cash Flows from Financing Activities. Net cash provided by financing activities for 2015 was $380 million compared to net cash used in financing activities of $808 million for 2014. During 2015, we:

- issued 25.3 million additional shares of common stock through a public equity offering and received net proceeds of approximately $815 million, which were used primarily to repay all borrowings under our credit facility and money market lines of credit; and
- issued $700 million 5 % Senior Notes due 2026 through a public debt offering and received net proceeds of $691 million in March 2015. In April 2015, we used the proceeds and cash on hand to redeem our $700 million aggregate principal of our 6 % Senior Subordinated Notes due 2020.
- During 2014, we 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 2015 decreased 26% compared to 2014. The table below summarizes our capital investments.

	Twelve Months Ended December 31,	
	2015	2014
	(In millions)	
Continuing operations:		
Exploration and development (exclusive of leasehold)	$1,112	$1,757
Acquisitions	128	33
Leasing proved and unproved property (leasehold)	176	119
Pipeline spending	3	9
Total continuing operations	1,419	1,918
Discontinued operations	—	12
Total	$1,419	$1,930

Restructuring

In April 2015, we announced plans to restructure our organization primarily in response to the current commodity price environment. See Note 16, "Restructuring Costs," to our consolidated financial statements in Item 8 of this report for additional details regarding our restructuring activities.

Contractual Obligations

The table below summarizes our significant contractual obligations due by year as of December 31, 2015.

		Year Ended December 31,					
	Total	2016	2017	2018	2019	2020	Thereafter
	(In millions)						
Long-term debt:							
Money market lines of credit	$39	$—	$—	$—	$—	$39	$—
5¾% Senior Notes due 2022	750	—	—	—	—	—	750
5 % Senior Notes due 2024	1,000	—	—	—	—	—	1,000
5 % Senior Notes due 2026	700	—	—	—	—	—	700
Total long-term debt	2,489	—	—	—	—	39	2,450
Other obligations[1]:							
Interest payments	1,185	138	138	138	137	137	497
Asset retirement obligations	194	2	3	12	3	3	171
Operating leases and other[2]	308	112	63	31	27	24	51
Firm transportation	337	88	84	67	54	20	24
Total other obligations	2,024	340	288	248	221	184	743
Total contractual obligations	$4,513	$340	$288	$248	$221	$223	$3,193

(1) Excludes assets and liabilities associated with our derivative contracts, which are dependent on the commodity price at the time of the contract settlement. For a discussion regarding our derivative contracts, see Note 4, "Derivative Financial Instruments," to our consolidated financial statements in Item 8 of this report.

(2) Includes agreements for office space, drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations are related to contracts for office space and drilling rigs and are included at the gross contractual value. Due to our various working interests where the drilling rig contracts will be utilized, it is not feasible to estimate a net contractual obligation. Net payments under these contracts are accounted for as capital additions to our oil and gas properties and could be less than the gross obligation disclosed.

We have various oil and gas production volume delivery commitments that are related to our Uinta Basin production. Given the decline in oil and natural gas prices and the related impact on our 2016 planned capital investments, as well as the potential impact on development plans in future years, we could fail to deliver the minimum production required under these commitments. In the event that we are unable to meet our crude oil volume delivery commitments, we incur deficiency fees ranging from $3.50 to $6.50 per barrel. Based on forecasted production levels for 2016, we are projected to incur approximately $15 million in deficiency fees related to these delivery commitments. See Items 1 and 2, “Business and Properties” for a description of our production and proved reserves. As of December 31, 2015, our delivery commitments through 2025 were as follows:

	Total	2016	2017	2018	2019	2020	Thereafter
Natural gas (MMMBtus)	20,285	20,285	—	—	—	—	—
Oil (MBbls)[1]	98,863	13,117	13,870	13,870	13,870	10,056	34,080

(1) Our oil delivery commitments are with two Salt Lake City, Utah refiners and relate to our Uinta Basin production. One delivery commitment is for approximately 18,000 barrels of oil per day through 2020. The second commitment is for 15,000 barrels of oil per day in January 2016, increasing to 20,000 barrels of oil per day by the end of the third quarter 2016, and continues at that level through August 2025.

Commitments under Joint Operating Agreements. Most of our properties are operated through joint ventures under joint operating or similar agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a “working interest” basis. The joint operating agreement provides remedies to the operator if a nonoperator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Oil and Gas Derivatives

We use derivative contracts to manage the variability in cash flows caused by commodity price fluctuations associated with our anticipated future oil and gas production for the next 24 to 36 months. As of December 31, 2015, we had no outstanding derivative contracts related to our NGL production. We do not use derivative instruments for trading purposes.

For a further discussion of our derivative activities, see "Critical Accounting Policies and Estimates — Commodity Derivative Activities" below and "Oil, Natural Gas and NGL Prices" in Item 7A of this report. See the discussion and tables in Note 4, "Derivative Financial Instruments," and Note 5, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open contracts and the estimated fair market value of those contracts as of December 31, 2015.

Between January 1, 2016 and February 19, 2016, we did not enter into additional derivative contracts.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for our judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. See Note 1, “Organization and Summary of Significant Accounting Policies,” to our consolidated financial statements in Item 8 of this report for a full description of the critical accounting policies and estimates below, as well as other accounting policies and estimates we make. Below are the most significant policies we apply in preparing our financial statements, some of which are subject to alternative treatments under generally accepted accounting principles. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with the Audit Committee of our Board of Directors.

Oil and Gas Activities.   Two generally accepted accounting methods are available for accounting for oil and gas producing activities — successful efforts and full cost. The most significant differences between these methods are the treatment of exploration costs and the manner in which the carrying values of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed, while these costs are capitalized under the full cost method. Both methods provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is a two-step test that compares the carrying value of the properties to the undiscounted cash flows to assess for impairment. If required, the impairment is the difference between the carrying value of individual oil and gas properties and their estimated fair value using forward-looking prices. Impairment under the full cost method requires an evaluation of the after-tax carrying value of oil and gas properties included in a cost center against the after-tax net present value of future cash flows from the related proved reserves, using SEC pricing, costs in effect at year-end and a 10% discount rate.

We use the full cost method of accounting for our oil and gas activities. Our financial position and results of operations would have been significantly different had we used the successful efforts method.

Proved Oil, Natural Gas and NGL Reserves. Our engineering estimates of proved oil, natural gas and NGL reserves directly impact financial accounting estimates, including DD&A expense and the full cost ceiling limitation. Proved oil, natural

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gas and NGL reserves are the estimated quantities of oil, natural gas and NGL reserves that geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs based on SEC pricing and under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors, including development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in commodity prices, operating costs and expected performance from a given reservoir will result in future revisions to our estimated proved reserves quantities. All reserve information in this report is based on estimates prepared by our petroleum engineering staff.

Full Cost Pool. Under the full cost method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits, interest and other internal costs directly attributable to these activities, are capitalized into country-based cost centers. Proceeds from the sale of oil and gas properties are applied as a reduction of the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. Future development and abandonment costs are added, and unevaluated costs are withheld from the net costs capitalized in cost centers to represent a full cost pool, which is amortized and assessed for impairment.

Future Development and Abandonment Costs. Future development costs include expected costs to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our gathering systems, production platforms and related structures and restoration costs of land and seabed. We estimate these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and information from our engineering consultants. Because these costs typically extend many years into the future, estimation is difficult and requires judgments that are subject to revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and abandonment costs annually, or more frequently if circumstances change.

The accounting guidance for future abandonment costs requires that a liability and corresponding long-lived asset for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred. The liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Holding all other factors constant, if our estimate of future development and abandonment costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense. To change our diluted earnings per share by $0.01 for the year ended December 31, 2015, our domestic DD&A rate would need to change by $0.17 per BOE, which would require a change in estimate of our domestic future development and abandonment costs of approximately 4%, or $87 million. Our China DD&A rate would need to change by $1.99 per BOE, which would require a change in estimate of our China future development and abandonment costs of approximately 499%, or $23 million.

Costs Withheld From Amortization. Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred, or a charge is made against earnings if the costs were incurred in a country for which a reserve base has not been established. Currently, there are no unevaluated properties for our China business.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2015, we had a total of $780 million of costs excluded from the respective full cost pools, all of which related to our domestic full cost pool. Inclusion of some or all of these costs in our domestic full cost pool, without adding any associated reserves, would have resulted in additional ceiling test writedowns.

Depreciation, Depletion and Amortization. The full cost pool for each country is amortized using a unit-of-production method based on the cost center's proved oil, natural gas and NGL reserves. Estimated proved reserves are a significant component of the calculation of DD&A expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test writedown. To change our diluted earnings per share for continuing operations by $0.01 for the year ended December 31, 2015, our domestic DD&A rate would need to change by $0.17 per BOE, which would require a change in the estimate of our domestic proved reserves of approximately 2%, or 8 MMBOE. Our China DD&A rate would need to change by $1.99 per BOE, which would require a change in the estimate of our China proved reserves of approximately 8%, or 1 MMBOE.

Full Cost Ceiling. Under the full cost method, we are subject to quarterly calculations of a “ceiling” or limitation on the amount of oil and gas property costs that can be capitalized on our balance sheet. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The ceiling value of oil, natural gas and NGL reserves is calculated based on SEC pricing and costs in effect as of the last day of the quarter. Once recorded, a ceiling test writedown is not reversible at a later date even if oil and gas prices increase.

Holding all other factors constant, it is likely that we will experience a ceiling test writedown in both the U.S. and China in the first quarter of 2016. 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 and development costs, upward or downward reserve revisions, reserve adds and tax attributes. Subject to these numerous factors and inherent limitations, we believe that impairments in the first quarter of 2016 could exceed $500 million.

Allocation of Purchase Price in Business Combinations. We monitor and screen for potential acquisitions of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we are required to record the excess as goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to recoverable oil and natural gas reserves and unproved properties is subject to the cost center ceiling as described under “— Full Cost Ceiling” above. The accounting standard for business combinations establishes how a purchaser recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree. The standard also sets forth guidance related to the recognition, measurement and disclosure related to goodwill acquired in a business combination or gains associated with a bargain purchase transaction.

Commodity Derivative Activities. Under accounting rules, we may elect to designate certain derivative contracts that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil and gas production. However, we do not designate any of our derivative contracts as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2015, we had net derivative assets of $367 million, of which 71%, based on total contracted volumes, was measured based upon a modified Black-Scholes valuation model and, as such, is classified as a Level 3 fair value measurement. The value of these contracts at their respective settlement dates could be significantly different than the fair value as of December 31, 2015. We periodically validate our valuations using independent third-party quotations. For further discussion of our derivative instruments and activities, see "Oil, Natural Gas and NGL Prices," in Item 7A of this report. Also see Note 4, "Derivative Financial Instruments," and Note 5, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open contracts and the estimated fair market value of those contracts as of December 31, 2015.

Stock-Based Compensation. We apply a fair value-based method of accounting for stock-based compensation, which requires recognition in the financial statements of the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. For equity awards, compensation expense is based on the fair value on the grant or modification date and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option-pricing model to measure the fair value of stock options and a Monte Carlo lattice-based model for our performance and market-based restricted stock and restricted stock units. We also have cash-settled restricted stock units that are accounted for under the liability method, which requires us to recognize the fair value of each award based on the underlying share price at the end of each period. See Note 14, “Stock-Based Compensation,” to our consolidated financial statements in Item 8 of this report for a full discussion of our stock-based compensation.

Income Taxes. The amount of income taxes recorded by the Company requires significant judgment by management and is reviewed and adjusted routinely based on changes in facts and circumstances. We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements. Utilization of deferred tax assets is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in oil, gas and NGL prices; estimates of the timing and amount of future production; and estimates of future operating and capital costs. Therefore, no certainty exists that we will be able to fully utilize deferred tax assets. We assess the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize deferred tax assets. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that some portion or all of the related deferred tax benefits will not be realized. Changes in judgment regarding future realizability of deferred tax assets may result in the reversal of all or a portion of the valuation allowance. In the period that determination is made, our net income will benefit from a lower effective tax rate. See Note 7, "Income Taxes," to our consolidated financial statements in Item 8 of this report for a full discussion of income taxes.

New Accounting Requirements

See Note 1, "Organization and Summary of Significant Accounting Policies," to our consolidated financial statements in Item 8 of this report for a discussion of new accounting requirements.

Regulation

Exploration, development, production and the sale of oil, gas and NGLs are subject to extensive federal, state, provincial, tribal, local and international regulations. An overview of these regulations is set forth in Items 1 and 2, "Business and Properties — Regulation." 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 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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from changes in oil, natural gas and NGL prices, interest rates and foreign currency exchange rates as discussed below.

Oil, Natural Gas and NGL Prices

Our decision on the quantity and price at which we choose to enter into derivative contracts is based in part on our view of current and future market conditions. While the use of derivative contracts can limit or reduce the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements. In addition, the use of derivative contracts may involve basis risk. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative contracts also involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2015, 10 of our 15 counterparties accounted for approximately 85% of our contracted volumes with the largest counterparty accounting for approximately 15%.

Of our expected 2016 crude oil production, 16,280 MBbls are partially protected against price volatility through the use of collars and swaps, all of which have associated sold puts. The sold puts limit our downward price protection below the weighted average price of our sold puts of $74.47 per barrel. If the market price remains below $74.47 per barrel, we receive the market price for our associated production plus the difference between our sold puts and the associated floors or fixed-price swaps, which averages $15.52 per barrel. For 6,242 MBbls of our 2016 volumes, we have locked in an average minimum premium of $13.62 over the market price through the use of purchased calls. The weighted average strike price of the purchased calls approximates the weighted average strike price of the sold puts, thereby effectively locking in the value. Of our expected 2017 crude oil production, 6,548 MBbls are partially protected against price volatility through the use of collars and swaps, all of which have associated sold puts. The sold puts limit our downward price protection below the weighted average price of our sold puts of $73.83 per barrel. If the market price remains below $73.83 per barrel, we receive the market price for our associated production plus the difference between our sold puts and the associated floors or fixed-price swaps, which averages $15.06 per barrel. For 5,647 MBbls of our 2017 volumes, we have locked in an average minimum premium of $13.40

over the market price through the use of purchased calls. For further discussion of our derivative instruments and activities, see Note 4, “Derivative Financial Instruments” to our consolidated financial statements in Item 8 of this report.

Interest Rates

At December 31, 2015, our debt was comprised of:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility and money market lines of credit	$—	$39
5¾% Senior Notes due 2022	750	—
5 % Senior Notes due 2024	1,000	—
5 % Senior Notes due 2026	700	—
	$2,450	$39

We consider our interest rate exposure to be minimal because 98% of our obligations were at fixed rates as of December 31, 2015, and our variable rate debt was at a weighted-average interest rate of approximately 2%. A 10% increase in LIBOR would not materially impact our interest costs on debt outstanding at December 31, 2015, but would decrease the fair value of our outstanding debt, as well as increase interest costs associated with future debt issuances or borrowings under our revolving credit facility and money market lines of credit.

Foreign Currency Exchange Rates

The functional currency for our China operations is the U.S. dollar. To the extent that business transactions in a foreign country are not denominated in the U.S. dollar, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts related to foreign currencies at December 31, 2015.

Item 8. Financial Statements and Supplementary Data

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AND SUPPLEMENTARY INFORMATION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our Company's management, including the Chief Executive Officer and the Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our internal control over financial reporting includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

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

Based on our evaluation under the framework in Internal Control — Integrated Framework (2013), the management of our Company concluded that our internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

Lee K. Boothby	Lawrence S. Massaro
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

The Woodlands, Texas
February 24, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Newfield Exploration Company:

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

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

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

Houston, Texas
February 24, 2016

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$5	$14
Accounts receivable, net	262	439
Inventories	34	33
Derivative assets	284	431
Other current assets	40	23
Total current assets	625	940
Oil and gas properties, net — full cost method ($780 and $677 were excluded from amortization at December 31, 2015 and 2014, respectively)	3,819	8,232
Other property and equipment, net	172	182
Derivative assets	105	190
Long-term investments	20	26
Other assets	27	10
Total assets	$4,768	$9,580
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$41	$32
Accrued liabilities	533	880
Advances from joint owners	58	34
Asset retirement obligations	2	3
Derivative liabilities	13	8
Deferred taxes	—	144
Total current liabilities	647	1,101
Other liabilities	48	45
Derivative liabilities	9	—
Long-term debt	2,467	2,874
Asset retirement obligations	192	183
Deferred taxes	26	1,484
Total long-term liabilities	2,742	4,586
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)	—	—
Common stock ($0.01 par value, 300,000,000 and 200,000,000 shares authorized at December 31, 2015 and 2014, respectively; 164,102,786 and 137,603,643 shares issued at December 31, 2015 and 2014, respectively)	2	1
Additional paid-in capital	2,436	1,576
Treasury stock (at cost, 612,469 and 275,069 shares at December 31, 2015 and 2014, respectively)	(22)	(10)
Accumulated other comprehensive gain (loss)	(2)	(1)
Retained earnings (deficit)	(1,035)	2,327
Total stockholders' equity	1,379	3,893
Total liabilities and stockholders' equity	$4,768	$9,580

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF OPERATIONS
(In millions, except per share data)

	Year Ended December 31,		
	2015	2014	2013
Oil, gas and NGL revenues	$1,557	$2,288	$1,857
Operating expenses:			
Lease operating	285	311	274
Transportation and processing	212	174	137
Production and other taxes	46	111	79
Depreciation, depletion and amortization	917	870	685
General and administrative	244	222	219
Ceiling test and other impairments	4,904	—	—
Other	10	25	13
Total operating expenses	6,618	1,713	1,407
Income (loss) from operations	(5,061)	575	450
Other income (expense):			
Interest expense	(164)	(200)	(205)
Capitalized interest	33	53	53
Commodity derivative income (expense)	259	610	(97)
Other, net	(14)	(6)	—
Total other income (expense)	114	457	(249)
Income (loss) from continuing operations before income taxes	(4,947)	1,032	201
Income tax provision (benefit):			
Current	17	5	(2)
Deferred	(1,602)	377	130
Total income tax provision (benefit)	(1,585)	382	128
Income (loss) from continuing operations	(3,362)	650	73
Income (loss) from discontinued operations, net of tax	—	250	74
Net income (loss)	$(3,362)	$900	$147
Earnings (loss) per share:			
Basic:			
Income (loss) from continuing operations	$(21.18)	$4.76	$0.39
Income (loss) from discontinued operations	—	1.83	0.55
Basic earnings (loss) per share	$(21.18)	$6.59	$0.94
Diluted:			
Income (loss) from continuing operations	$(21.18)	$4.71	$0.39
Income (loss) from discontinued operations	—	1.81	0.55
Diluted earnings (loss) per share	$(21.18)	$6.52	$0.94
Weighted-average number of shares outstanding for basic earnings (loss) per share	159	137	135
	159	138	136

Weighted-average number of shares outstanding for diluted
earnings
(loss) per share

The accompanying notes to consolidated financial statements are an integral part of this statement.

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NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2015	2014	2013
Net income (loss)	$(3,362)	$900	$147
Other comprehensive income (loss):			
Unrealized gain (loss) on investments, net of tax of $0 for the years ended December 31, 2015 and 2014, and ($3) for the year ended December 31, 2013	—	—	7
Unrealized gain (loss) on post-retirement benefits, net of tax of $0 for the year ended December 31, 2015, $2 for the year ended December 31, 2014, and ($1) for the year ended December 31, 2013	(1)	(3)	2
Other comprehensive income (loss), net of tax	(1)	(3)	9
Comprehensive income (loss)	$(3,363)	$897	$156

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$(3,362)	$900	$147
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	917	903	930
Deferred tax provision (benefit)	(1,602)	509	143
Stock-based compensation	25	28	43
Unrealized (gain) loss on derivative contracts	246	(649)	157
Gain on sale of Malaysia business	—	(373)	—
Ceiling test and other impairment	4,904	—	—
Other, net	43	21	14
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	83	47	(62)
(Increase) decrease in inventories	(2)	—	(11)
(Increase) decrease in other current assets	(17)	(30)	12
(Increase) decrease in other assets	(8)	2	6
Increase (decrease) in accounts payable and accrued liabilities	(45)	21	74
Increase (decrease) in advances from joint owners	24	5	(1)
Increase (decrease) in other liabilities	3	3	(7)
Net cash provided by (used in) operating activities	1,209	1,387	1,445
Cash flows from investing activities:			
Additions to oil and gas properties	(1,607)	(2,064)	(1,987)
Acquisitions of oil and gas properties	(125)	(33)	(72)
Proceeds from sales of oil and gas properties	90	620	36
Proceeds received from sale of Malaysia business, net	—	809	—
Additions to other property and equipment	(13)	(31)	(36)
Redemptions of investments	—	39	1
Proceeds from insurance settlement, net	57	—	—
Net cash provided by (used in) investing activities	(1,598)	(660)	(2,058)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	1,908	2,949	3,263
Repayments of borrowings under credit arrangements	(2,315)	(3,152)	(2,614)
Proceeds from issuance of senior notes	691	—	—
Repayment of senior subordinated notes	(700)	(600)	—
Debt issue costs	(8)	—	(4)
Proceeds from issuances of common stock, net	819	6	1
Repurchase of preferred shares of subsidiary	—	—	(20)
Purchases of treasury stock, net	(12)	(11)	(6)
Other	(3)	—	—
Net cash provided by (used in) financing activities	380	(808)	620
Increase (decrease) in cash and cash equivalents	(9)	(81)	7
Cash and cash equivalents, beginning of period	14	95	88
Cash and cash equivalents, end of period	$5	$14	$95

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In millions)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Gain (Loss)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance, December 31, 2012	136.5	$1	(1.2)	$(36)	$ 1,522	$1,300	$ (7)	$ 2,780
Issuances of common stock	0.2	—			1			1
Stock-based compensation					45			45
Treasury stock, net			0.7	23	(29)			(6)
Net income (loss)						147		147
Other comprehensive income (loss), net of tax							9	9
Repurchase of preferred shares of subsidiary						(20)		(20)
Balance, December 31, 2013	136.7	1	(0.5)	(13)	1,539	1,427	2	2,956
Issuances of common stock	0.9	—			6			6
Stock-based compensation					45			45
Treasury stock, net			0.2	3	(14)			(11)
Net income (loss)						900		900
Other comprehensive income (loss), net of tax							(3)	(3)
Balance, December 31, 2014	137.6	1	(0.3)	(10)	1,576	2,327	(1)	3,893
Issuances of common stock	26.5	1			818			819
Stock-based compensation					42			42
Treasury stock, net			(0.3)	(12)	—			(12)
Net income (loss)						(3,362)		(3,362)
Other comprehensive income (loss), net of tax							(1)	(1)
Balance, December 31, 2015	164.1	$2	(0.6)	$(22)	$ 2,436	$(1,035)	$ (2)	$ 1,379

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies

Organization and Principles of Consolidation

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids (NGLs). Our operations are focused primarily on large scale, onshore liquids-rich resource plays in the United States. Our principal areas of operation are the Anadarko and Arkoma basins of Oklahoma, the Williston Basin of North Dakota, the Uinta Basin of Utah and the Maverick and Gulf Coast basins of Texas. In addition, we have oil developments offshore China.

Our consolidated financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. We proportionately consolidate our interests in oil and natural gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to “Newfield,” “we,” “us,” “our” or the “Company” are to Newfield Exploration Company and its subsidiaries.

Risks and Uncertainties

As an independent oil and natural gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for oil, natural gas and NGLs. Historically, the energy markets have been very volatile, and there can be no assurance that commodity prices will not be subject to wide fluctuations in the future. A substantial or extended decline in commodity prices could have a material adverse effect on our financial position, results of operations, cash flows, access to capital and on the quantities of oil, natural gas and NGL reserves that we can economically produce. Other risks and uncertainties that could affect us in the current price environment include, but are not limited to, counterparty credit risk for our receivables, responsibility for decommissioning liabilities for offshore interests we no longer own, access to credit markets and ability to meet financial ratios and covenants in our financing agreements.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities; disclosure of contingent assets and liabilities at the date of the financial statements; the reported amounts of revenues and expenses during the reporting period; and the quantities and values of proved oil, natural gas and NGL reserves used in calculating depletion and assessing impairment of our oil and gas properties. Actual results could differ significantly from these estimates. Our most significant estimates are associated with the quantities of proved oil, natural gas and NGL reserves, the timing and amount of transfers of our unevaluated properties into our amortizable full cost pool, the recoverability of our deferred tax assets and the fair value of both our derivative contracts and our stock-based compensation liability awards.

Restructuring Costs

Restructuring costs include severance and related benefit costs, costs associated with abandoned office space, employee relocation costs and other associated costs. Employee severance and related benefit costs are recognized on a straight-line basis over the required service period, if any. Employee relocation costs are expensed as incurred. On the date a leased property ceases to be used, a liability for non-cancellable office-lease costs associated with restructuring is recognized and measured at fair value on our consolidated balance sheet. Fair value estimates include assumptions regarding estimated future sublease payments. These estimates could materially differ from actual results and may require revision to initial estimates of the liability. See Note 16, "Restructuring Costs," for additional disclosures.

Reclassifications and Out-of-Period Adjustments

Certain reclassifications were made to prior years' reported amounts in order to conform to the current year presentation. These reclassifications did not impact our net income (loss), stockholders' equity or cash flows.

The Company's production and other taxes for continuing operations for the year ended December 31, 2015 were reduced by approximately $7 million in the fourth quarter due to an adjustment related to our 2013 and 2014 severance tax returns. The Company does not believe the correcting adjustments are material to these consolidated financial statements.

Discontinued Operations

The results of our Malaysia operations are reflected separately as discontinued operations in the consolidated statement of operations on a line immediately after "Income (loss) from continuing operations." See Note 19, "Discontinued Operations," for additional disclosures, as well as information regarding the sale of our Malaysia business, which closed in February 2014. These financial statements and notes are inclusive of our Malaysia operations unless otherwise noted.

Revenue Recognition

Substantially all of our oil, natural gas and NGLs are sold at market-based prices to a variety of purchasers 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. We record revenue when we deliver our production to the customer and collectability is reasonably assured. Revenues from the production of oil, natural gas and NGLs on properties in which we have joint ownership are recorded under the sales method. Under the sales method, the Company and other joint owners may sell more or less than their entitled share of production. Should the Company's excess sales exceed our share of estimated remaining recoverable reserves, a liability is recorded. Differences between sales and our entitled share of production are not material.

Foreign Currency

The functional currency for our China operations is the U.S. dollar. Gains and losses incurred on transactions in a currency other than the U.S. dollar are recorded under the caption "Other income (expense) — Other, net" on our consolidated statement of operations.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with a maturity of three months or less when acquired and are stated at cost, which approximates fair value. We invest cash in excess of near-term capital and operating requirements in U.S. Treasury Notes, Eurodollar time deposits and money market funds, which are classified as cash and cash equivalents on our consolidated balance sheet.

Restricted Cash

We have restricted cash of $13 million included in "Other assets" on our consolidated balance sheet at December 31, 2015 that represents amounts held in escrow accounts to satisfy future plug and abandonment obligations for our China operations. These amounts are restricted as to their current use and will be released as we plug and abandon wells and facilities in our China field. Consistent with our other plug and abandonment activities, changes in restricted cash are included in cash flows from operating activities in our consolidated statement of cash flows.

Investments

Investments consist of debt and equity securities, a majority of which are classified as "available-for-sale" and stated at fair value. Accordingly, unrealized gains and losses and the related deferred income tax effects are excluded from earnings and reported in other comprehensive income within our consolidated statement of stockholders' equity. Realized gains or losses are computed based on specific identification of the securities sold. We regularly assess our investments for impairment and consider any impairment to be other than temporary if we intend to sell the security, it is more likely than not that we will be required to sell the security, or we do not expect to recover our cost of the security.

Allowance for Doubtful Accounts

We routinely assess material trade and other receivables to determine their collectability. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, our oil and gas receivables are collected within 45 to 60 days of production. We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected.

Inventories

Inventories primarily consist of tubular goods and well equipment held for use in our oil and natural gas operations and oil produced but not sold in our China operations. Inventories are carried at the lower of cost or market. Substantially all of the crude oil from our offshore operations in China is produced into floating storage facilities and sold periodically as barge quantities are accumulated. The carrying value of oil inventory is the sum of related production costs and depletion expense. See Note 3, "Inventories," for further discussion.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits, interest and other internal costs directly attributable to these activities, are capitalized into country-based cost centers.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. During the first quarter of 2014, we sold our Malaysia business, which constituted the entire full cost pool for Malaysia. See Note 19, "Discontinued Operations," for further discussion.

Capitalized costs and estimated future development costs are amortized using a unit-of-production method based on proved reserves associated with the applicable cost center. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling. A particular cost center ceiling is equal to the sum of:

- the present value (10% per annum discount rate) of estimated future net revenues from proved reserves using oil, natural gas and NGL reserve estimation requirements, which require use of the unweighted average first-day-of-the-month commodity prices for the prior 12 months (SEC pricing), adjusted for market differentials, applicable to our reserves (including the effects of derivative contracts that are designated for hedge accounting, if any); plus
- the costs of properties not included in the costs being amortized, if any; less
- related income tax effects.

If net capitalized costs of 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 and, holding other factors constant, results in lower depreciation, depletion and amortization expense in future periods.

The risk that we will be required to writedown the carrying value of our oil and gas properties increases when oil, natural gas and NGL prices decrease significantly for a prolonged period, or if we have substantial downward revisions in our estimated proved reserves.

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred, or a charge is made against earnings if the costs were incurred in a country for which a reserve base has not been established.

See Note 6, "Oil and Gas Properties and Other Property and Equipment," for a detailed discussion regarding our oil and gas property and equipment, and our asset acquisitions and sales transactions.

Other Property and Equipment

Furniture, fixtures and equipment are recorded at cost and are depreciated using the straight-line method over their estimated useful lives, which range from three to seven years. Gathering systems and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives of 25 years.

Accounting for Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, we record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and capitalize the present value of the asset retirement cost in oil and gas properties in the period in which the ARO is incurred. Settlements include payments made to satisfy the AROs, as well as transfer of the AROs to purchasers of our divested properties.

In general, the amount of the initial recorded ARO and the costs capitalized will equal the estimated future costs to satisfy the abandonment obligation assuming normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using the credit adjusted risk-free rate for our Company. After recording these amounts, the ARO is accreted to its future estimated value and the original capitalized costs are depreciated on a unit-of-production basis within the related full cost pool. Both the accretion and the depreciation are included in depreciation, depletion and amortization expense on our consolidated statement of operations. See Note 9, "Asset Retirement Obligations," for further discussion.

Contingencies

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated. See Note 11, “Commitments and Contingencies,” for a more detailed discussion regarding our contingencies.

Environmental Matters

Environmental costs that relate to current operations are expensed as incurred. Remediation costs that relate to an existing condition caused by past operations are accrued when it is probable that those costs will be incurred and can be reasonably estimated based upon evaluations of currently available facts related to each site.

Income Taxes

We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements. We assess the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize deferred tax assets. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. We also evaluate potential uncertain tax positions, and if necessary, establish accruals for such items. See Note 7, "Income Taxes," for further discussion.

Stock-Based Compensation

We apply a fair value-based method of accounting for stock-based compensation, which requires recognition in the financial statements of the cost of services received in exchange for awards of equity instruments based on the grant date fair value of those awards. For equity awards, compensation expense is based on the fair value on the grant or modification date and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option-pricing model to measure the fair value of stock options and a Monte Carlo lattice-based model for our performance and market-based restricted stock and restricted stock units. We also have cash-settled restricted stock units that are accounted for under the liability method, which requires us to recognize the fair value of each award based on the underlying share price at the end of each period. See Note 14, "Stock-Based Compensation," for a full discussion of our stock-based compensation.

Concentration of Credit Risk

We operate a substantial portion of our oil and gas properties. As the operator of a property, we make full payment for costs associated with the property and seek reimbursement from the other working interest owners in the property for their share of those costs. Our joint interest owners consist primarily of independent oil and gas producers whose ability to reimburse us could be negatively impacted by adverse market conditions.

The purchasers of our oil, gas and NGL production consist primarily of independent marketers, major oil and gas companies, refiners and gas pipeline companies. We perform credit evaluations of the purchasers of our production and monitor their financial condition on an ongoing basis. Based on our evaluations and monitoring, we obtain cash escrows, letters of credit or parental guarantees from some purchasers.

All of our derivative transactions were carried out in the over-the-counter market and are not typically subject to margin-deposit requirements. The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The counterparties for all of our derivative transactions have an "investment grade" credit rating. We monitor the credit ratings of our hedging counterparties on an ongoing basis. Although we have entered into derivative contracts with multiple counterparties to mitigate our exposure to any individual counterparty, if any of our counterparties were to default on its obligations to us under the derivative contracts or seek bankruptcy protection, it 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 volatility. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened and fewer counterparties may participate in 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. At December 31, 2015, 10 of our 15 counterparties accounted for approximately 85% of our contracted volumes, with the largest counterparty accounting for approximately 15%. Approximately 70% of our volumes subject to derivative instruments are with lenders under our credit facility. Our credit facility, senior notes and substantially all of our derivative instruments contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

Major Customers

China National Offshore Oil Corporation Ltd., MidCon Gathering LLC and Sunoco Logistics Partners Operations GP LLC accounted for 13%, 11% and 10%, respectively, of our total revenues in 2015. During 2014, Tesoro Corporation and Sunoco Logistics Partners Operations GP LLC accounted for 12% and 10%, respectively, of our total revenues. During 2013, sales of our oil and gas production to Sunoco Logistics Partners Operations GP LLC, Royal Dutch Shell plc and Tesoro Corporation accounted for 13%, 12% and 11%, respectively, of our total revenues. We believe that the loss of any of our major customers would not have a material adverse effect on us because alternative purchasers are available.

Derivative Financial Instruments

Our derivative instruments are recorded on the consolidated balance sheet at fair value as either an asset or a liability with changes in fair value recognized currently in earnings. While we utilize our derivative instruments to manage the price risk attributable to our expected oil and gas production, we have elected not to designate our derivative instruments as accounting hedges under the accounting guidance.

The related cash flow impact of our derivative activities are reflected as cash flows from operating activities unless they are determined to have a significant financing element at inception, in which case they are classified within financing activities. See Note 4, “Derivative Financial Instruments,” for a more detailed discussion of our derivative activities.

Offsetting Assets and Liabilities

Our derivative financial instruments are subject to master netting arrangements and are reflected on our consolidated balance sheet accordingly. See Note 4, "Derivative Financial Instruments," for details regarding the gross amounts, as well as the impact of our netting arrangements on our net derivative position. We only offset assets and liabilities in relation to our derivative financial instruments.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

New Accounting Requirements

In November 2015, the Financial Accounting Standards Board (FASB) issued guidance regarding the presentation of deferred income taxes in the balance sheet and requires that within a particular jurisdiction, deferred tax liabilities and assets, as well as any related valuation allowance, be offset and classified as a single noncurrent amount. The guidance is effective for interim and annual periods beginning after December 15, 2016. We early adopted this guidance in 2015 on a prospective basis as permitted by the guidance.

In April 2015, the FASB issued guidance regarding the presentation of debt issuance costs in the financial statements and requires that debt issuance costs be presented as a reduction of the carrying value of the financial liability and not as a separate asset. The guidance requires retrospective adjustment to the balance sheet presentation and disclosures applicable for a change in an accounting principle. The guidance is effective for interim and annual periods beginning after December 15, 2015. We early adopted this guidance in 2015 as permitted by the guidance.

In August 2014, the FASB issued guidance regarding disclosures of uncertainties about an entity's ability to continue as a going concern. The guidance applies prospectively to all entities, requiring management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern and disclose certain information when substantial doubt is raised. The guidance is effective for interim and annual periods beginning on or after December 15, 2016. We will adopt this guidance in the first quarter of 2017.

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings (deficit). In July 2015, the FASB approved a deferral of the effective date by one year. As a result, the guidance is effective for interim and annual periods beginning on or after December 15, 2017. We are currently evaluating the impact of this guidance on our financial statements.

2. Accounts Receivable

Accounts receivable consisted of the following at December 31:

	2015	2014
	(In millions)	
Revenue	$94	$155
Joint interest	125	230
Other	59	70
Reserve for doubtful accounts	(16)	(16)
Total accounts receivable, net	$262	$439

Reserve for doubtful accounts at December 31, 2015 and 2014 includes an allowance for $15 million related to discontinued operations. See Note 19, "Discontinued Operations."

3. Inventories

During 2015 and 2014, we had inventory writedowns of $5 million and $9 million, respectively. These writedowns are included in “Operating expenses — Other” on our consolidated statement of operations. We had no inventory impairments in 2013. At December 31, 2015 and 2014, the crude oil inventory from our China operations consisted of approximately 335,000 and 240,000 barrels of crude oil, respectively.

4. Derivative Financial Instruments

Commodity Derivative Instruments

We utilize the following derivative strategies, which consist of either a single derivative instrument or a combination of instruments, to manage the variability in cash flows associated with the forecasted sale of our domestic oil and natural gas production.

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

- Fixed-price swaps. With respect to a swap position, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap strike price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap strike price.
- Collars (combination of purchased put options (floor) and sold call options (ceiling)). For a collar position, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor strike price while we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling strike price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor strike price and equal to or less than the ceiling strike price.
- Fixed-price swaps with sold puts. A swap with a sold put position consists of a standard swap position plus a put sold by us with a strike price below the associated fixed-price swap. This structure enables us to increase the fixed-price swap with the value received through the sale of the put. If the settlement price for any settlement period falls equal to or below the put strike price, then we will only receive the difference between the swap price and the put strike price. If the settlement price is greater than the put strike price, the result is the same as it would have been with a standard swap only.
- Collars with sold puts. A collar with a sold put position consists of a standard collar position plus a put sold by us with a strike price below the floor strike price of the collar. This structure enables us to improve the collar strike prices with the value received through the sale of the additional put. If the settlement price for any settlement period falls equal to or below the additional put strike price, then we will receive the difference between the floor strike price and the additional put strike price. If the settlement price is greater than the additional put strike price, the result is the same as it would have been with a standard collar only.
- Purchased calls. These purchased calls are options that require a counterparty to make a payment to us if the settlement price is above the call strike price (excluding the effects of deferred premium owed by us to the counterparty). As a result, these positions lock in the value of a portion of our corresponding oil swaps with sold puts as well as collars with sold puts. Our total deferred premium associated with these purchased calls was $22 million at December 31, 2015.

While the use of these derivative instruments may limit or partially reduce the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements. For discussion of the accounting policies associated with our derivative financial instruments (including the offsetting of derivative assets and liabilities), see Note 1, "Organization and Summary of Significant Accounting Policies."

Our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, estimated volatility, non-performance risk adjustments using credit default swaps, interest rates and time to maturity. The calculation of the fair value of options requires the use of an option-pricing model. See Note 5, “Fair Value Measurements.”

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At December 31, 2015, we had outstanding derivative positions as set forth in the tables below.

Crude Oil

Period and Type of Instrument	Volume in MBbls	NYMEX Contract Price Per Bbl Swaps (Weighted Average)	Purchased Calls (Weighted Average)	Sold Puts(Weighted Average) (1)	Collars Floors (Weighted Average)	Ceilings (Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
2016:							
Fixed-price swaps with sold puts:	10,060						
Fixed-price swaps		$89.98	$—	$ —	$—	$—	$487
Sold puts		—	—	74.14	—	—	(331)
Collars with sold puts:	6,220						
Collars		—	—	—	90.00	96.15	300
Sold puts		—	—	75.00	—	—	(209)
Purchased calls	6,242	—	72.18	—	—	—	2
2017:							
Fixed-price swaps with sold puts:	4,468						
Fixed-price swaps		88.37	—	—	—	—	183
Sold puts		—	—	73.28	—	—	(122)
Collars with sold puts:	2,080						
Collars		—	—	—	90.00	95.59	90
Sold puts		—	—	75.00	—	—	(61)
Purchased calls	5,647	—	73.71	—	—	—	6
Total							$345

(1) If the market prices remain below our sold puts at contract settlement, we will receive the market price plus the following associated with our production:

- the difference between our floor price and our sold put price for collars with sold puts; or
- the difference between our swap price and our sold put price for fixed-price swaps with sold puts.

For the volumes with purchased calls, we have effectively locked in a portion of the difference between the purchased call price and the sold put price noted above (less the deferred call premium).

Natural Gas

Period and Type of Instrument	Volume in MMMBtus	NYMEX Contract Price Per MMBtu Swaps (Weighted Average)	Collars Floors(Weighted Average)	Ceilings(Weighted Average)	Estimated Fair Value Asset (Liability) (In millions)
2016:					
Fixed-price swaps	4,550	$3.39	$—	$ —	$5
Collars	10,980	—	4.00	4.54	17

Total	$22

NEWFIELD EXPLORATION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Additional Disclosures about Derivative Instruments

We had derivative financial instruments recorded in our consolidated balance sheet as assets (liabilities) at their respective estimated fair value, as set forth below.

	Derivative Assets				Derivative Liabilities			
	Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location Current	Noncurrent	Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location Current	Noncurrent
December 31, 2015	(In millions)				(In millions)			
Oil positions	$1,005	$(638)	$262	$105	$(660)	$638	$(13)	$(9)
Natural gas positions	22	—	22	—	—	—	—	—
Total	$1,027	$(638)	$284	$105	$(660)	$638	$(13)	$(9)
December 31, 2014								
Oil positions	$1,115	$(597)	$332	$186	$(605)	$597	$(8)	$—
Natural gas positions	105	(2)	99	4	(2)	2	—	