CONTINENTAL RESOURCES, INC
Form 10-K
February 21, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

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FORM 10-K

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(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
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: 001-32886

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CONTINENTAL RESOURCES, INC.
(Exact name of registrant as specified in its charter)

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| Oklahoma | 73-0767549 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 20 N. Broadway, Oklahoma City, Oklahoma | 73102 |
| (Address of principal executive offices) | (Zip Code) |

Registrant's telephone number, including area code: (405) 234-9000
Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock, $0.01 par value | New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: None

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Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

| | | | |
|---|---|---|---|
| Large accelerated filer | x | Accelerated filer | ¨ |
| Non-accelerated filer | ¨ (Do not check if a smaller reporting company) | Smaller reporting company | ¨ |
| | | Emerging growth company | ¨ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2017 was approximately $2.8 billion, based upon the closing price of $32.33 per share as reported by the New York Stock Exchange on such date.

375,215,902 shares of our $0.01 par value common stock were outstanding on January 31, 2018.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Continental Resources, Inc. for the Annual Meeting of Shareholders to be held in May 2018, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Form 10-K.

Table of Contents

Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section may be used throughout this report:

“basin” A large natural depression on the earth’s surface in which sediments generally brought by water accumulate.

“Bbl” One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

“Bcf” One billion cubic feet of natural gas.

“Boe” Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.

“Btu” British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

“completion” The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

“conventional play” An area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

“DD&A” Depreciation, depletion, amortization and accretion.

“de-risked” Refers to acreage and locations in which the Company believes the geological risks and uncertainties related to recovery of crude oil and natural gas have been reduced as a result of drilling operations to date. However, only a portion of such acreage and locations have been assigned proved undeveloped reserves and ultimate recovery of hydrocarbons from such acreage and locations remains subject to all risks of recovery applicable to other acreage.

“developed acreage” The number of acres allocated or assignable to productive wells or wells capable of production.

“development well” A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“dry gas” Refers to natural gas that remains in a gaseous state in the reservoir and does not produce large quantities of liquid hydrocarbons when brought to the surface. Also may refer to gas that has been processed or treated to remove all natural gas liquids.

“dry hole” Exploratory or development well that does not produce crude oil and/or natural gas in economically producible quantities.

“enhanced recovery” The recovery of crude oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are sometimes applied when production slows due to depletion of the natural pressure.

“exploratory well” A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.

“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. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“formation” A layer of rock which has distinct characteristics that differs from nearby rock.

“fracture stimulation” A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production. Also may be referred to as hydraulic fracturing.

“gross acres” or “gross wells” Refers to the total acres or wells in which a working interest is owned.

“held by production” or “HBP” Refers to an oil and gas lease continued into effect into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

“horizontal drilling” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

“MBbl” One thousand barrels of crude oil, condensate or natural gas liquids.

"MBoe" One thousand Boe.
"Mcf" One thousand cubic feet of natural gas.
"MMBo" One million barrels of crude oil.
"MMBoe" One million Boe.
"MMBtu" One million British thermal units.
"MMcf" One million cubic feet of natural gas.
"net acres" or "net wells" Refers to the sum of the fractional working interests owned in gross acres or gross wells.
"NYMEX" The New York Mercantile Exchange.
"pad drilling" or "pad development" Describes a well site layout which allows for drilling multiple wells from a single pad resulting in less environmental impact and lower per-well drilling and completion costs.
"play" A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.
"productive well" A well found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
"prospect" A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.
"proved reserves" The quantities of crude 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 renewal is reasonably certain.
"proved developed reserves" Reserves expected to be recovered through existing wells with existing equipment and operating methods.
"proved undeveloped reserves" or "PUD" Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion.
"PV-10" When used with respect to crude oil and natural gas reserves, PV-10 represents the estimated future gross revenues to be generated from the production of proved reserves using a 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December, net of estimated production and future development and abandonment costs based on costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Securities and Exchange Commission ("SEC"). PV-10 is not a financial measure calculated in accordance with generally accepted accounting principles ("GAAP") and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Company's crude oil and natural gas properties. The Company and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.
"reservoir" A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
"resource play" Refers to an expansive contiguous geographical area with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and completion technologies.
"royalty interest" Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.
"SCOOP" Refers to the South Central Oklahoma Oil Province, a term used to describe properties located in the Anadarko basin of Oklahoma in which we operate. Our SCOOP acreage extends across portions of Garvin, Grady, Stephens, Carter, McClain and Love counties of Oklahoma and has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation.

“STACK” Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe a resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage and Woodford formations. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma.

“spacing” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.

“Standardized Measure” Discounted future net cash flows estimated by applying the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax net cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis in the crude oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

“step-out well” or “step outs” A well drilled beyond the proved boundaries of a field to investigate a possible extension of the field.

“three dimensional (3D) seismic” Seismic surveys using an instrument to send sound waves into the earth and collect data to help geophysicists define the underground configurations. 3D seismic provides three-dimensional pictures. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We also use 3D seismic to identify sub-surface hazards to assist in steering, avoiding hazards and determining where to perform optimized completions.

“unconventional play” An area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but may lack readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These areas tend to have low permeability and may be closely associated with source rock, as is the case with oil and gas shale, tight oil and gas sands and coalbed methane, and generally require horizontal drilling, fracture stimulation treatments or other special recovery processes in order to achieve economic production. In general, unconventional plays require the application of more advanced technology and higher drilling and completion costs to produce relative to conventional plays.

“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 crude oil and/or natural gas.

“unit” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

“well bore” The hole drilled by the bit that is equipped for crude oil or natural gas production on a completed well. Also called a well or borehole.

“working interest” The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Cautionary Statement for the Purpose of the “Safe Harbor” Provisions of the Private Securities Litigation Reform Act of 1995

This report and information incorporated by reference in this report include “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company’s business and statements or information concerning the Company’s future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, included in this report are forward-looking statements. The words “could,” “may,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “budget,” “plan,” “continue,” “potential,” “guidance,” “strate
expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include, but are not limited to, statements about:

- our strategy;
- our business and financial plans;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- technology;
- future crude oil, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing of wells;
- competition;
- marketing of crude oil and natural gas;
- transportation of crude oil, natural gas liquids, and natural gas to markets;
- property exploitation, property acquisitions and dispositions, or joint development opportunities;
- costs of exploiting and developing our properties and conducting other operations;
- our financial position;
- general economic conditions;
- credit markets;
- our liquidity and access to capital;
- the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us and of scheduled or potential regulatory or legal changes;
- our future operating and financial results;
- our future commodity or other hedging arrangements; and
- the ability and willingness of current or potential lenders, hedging 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.

Forward-looking statements are based on the Company’s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company’s control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate or will not change over time. The risks and uncertainties that may affect the operations, performance and results of the business and forward-looking statements include, but are not limited to, those risk factors and other cautionary statements described under Part I, Item 1A. Risk Factors and elsewhere in this report, registration statements we file from time to time with the Securities and Exchange Commission, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, the Company’s actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement.

Except as expressly stated above or otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this report, or otherwise.

Part I

You should read this entire report carefully, including the risks described under Part I, Item 1A. Risk Factors and our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this report. Unless the context otherwise requires, references in this report to “Continental Resources,” “Continental,” “we,” “us,” “our,” “ours” or “the Company” refer to Continental Resources, Inc. and its subsidiaries.

Item 1. Business

General

We are an independent crude oil and natural gas company with properties in the North, South and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP (South Central Oklahoma Oil Province) and STACK (Sooner Trend Anadarko Canadian Kingfisher) areas of Oklahoma. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.

We were formed in 1967 to explore for, develop and produce crude oil and natural gas properties. Through the 1980s, our activities and growth remained focused primarily in Oklahoma. In the 1980s, we expanded our activity into the North region. The North region comprised approximately 59% of our crude oil and natural gas production and approximately 69% of our crude oil and natural gas revenues for the year ended December 31, 2017. The Company’s principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. Approximately 50% of our estimated proved reserves as of December 31, 2017 are located in the North region. In recent years, we have significantly expanded our operations in our South region with our increased activity in the SCOOP and STACK plays. The South region comprised approximately 41% of our crude oil and natural gas production, 31% of our crude oil and natural gas revenues, and 50% of our estimated proved reserves as of and for the year ended December 31, 2017.

We focus our exploration activities in large new or developing crude oil and natural gas plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where three dimensional seismic, horizontal drilling, geosteering technologies, advanced completion technologies (e.g., fracture stimulation) and enhanced recovery technologies allow us to develop and produce crude oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drill bit.

As of December 31, 2017, our estimated proved reserves were 1,331 MMBoe, with estimated proved developed reserves of 602 MMBoe, or 45% of our total estimated proved reserves. Crude oil represents approximately 48% of our estimated proved reserves as of December 31, 2017. The standardized measure of our discounted future net cash flows totaled approximately $10.5 billion at December 31, 2017.

For 2017, we generated crude oil and natural gas revenues of $2.98 billion and operating cash flows of $2.08 billion. Crude oil accounted for approximately 57% of our total production and approximately 78% of our crude oil and natural gas revenues for 2017. Production averaged 242,637 Boe per day for 2017, a 12% increase compared to average production of 216,912 Boe per day for 2016. Average daily production for the quarter ended December 31, 2017 increased 37% to 286,985 Boe per day compared to 209,861 Boe per day for the quarter ended December 31, 2016 due to increased drilling and completion activities.

The table below summarizes our total estimated proved reserves, PV-10 (non-GAAP) and net producing wells as of December 31, 2017, average daily production for the quarter ended December 31, 2017 and the reserve-to-production index in our principal operating areas. The PV-10 values shown below are not intended to represent the fair market value of our crude oil and natural gas properties. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. See Part I, Item 1A. Risk Factors and “Critical Accounting Policies and Estimates” in Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations of this report for further discussion of uncertainties inherent in the reserve estimates.

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| | December 31, 2017 | | | | Average daily production for fourth quarter 2017 (Boe per day) | | |
|---|---|---|---|---|---|---|---|
| | Proved reserves (MBoe) | Percent of total | PV-10 (1) (In millions) | Net producing wells | | Percent of total | Annualized reserve/production index (2) |
| North Region: | | | | | | | |
| Bakken field | | | | | | | |
| North Dakota Bakken | 594,818 | 44.7 % | $ 6,488 | 1,313 | 158,640 | 55.3 % | 10.3 |
| Montana Bakken | 40,703 | 3.1 % | 412 | 263 | 6,958 | 2.4 % | 16.0 |
| Red River units | | | | | | | |
| Cedar Hills | 28,998 | 2.2 % | 340 | 130 | 7,022 | 2.4 % | 11.3 |
| Other Red River units | 2,668 | 0.2 % | 28 | 117 | 2,475 | 0.9 % | 3.0 |
| Other | 1,356 | 0.1 % | 9 | 8 | 468 | 0.2 % | 7.9 |
| South Region: | | | | | | | |
| SCOOP | 491,776 | 36.9 % | 3,597 | 260 | 62,242 | 21.7 % | 21.6 |
| STACK | 167,390 | 12.6 % | 936 | 160 | 47,914 | 16.7 % | 9.6 |
| Other | 3,286 | 0.2 % | 23 | 175 | 1,266 | 0.4 % | 7.1 |
| Total | 1,330,995 | 100.0% | $ 11,833 | 2,426 | 286,985 | 100.0% | 12.7 |

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately $1.4 billion. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the crude oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific income tax characteristics of such entities. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for further discussion.

(2) The Annualized Reserve/Production Index is the number of years that estimated proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2017 production into estimated proved reserve volumes as of December 31, 2017.

Business Environment and Outlook

Our industry has been significantly impacted by lower commodity prices in recent years. The downward pressure on prices experienced in 2015 and 2016 showed signs of easing in 2017. Commodity prices remained volatile during the year, but generally increased on average in 2017 relative to 2016 in response to improving domestic and global supply and demand fundamentals and other factors. Crude oil prices in particular showed significant signs of improvement in late 2017 and early 2018, with West Texas Intermediate crude oil benchmark prices reaching a three-year high of $66 per barrel in January 2018. Crude oil prices remain volatile and it is uncertain whether the increase in market prices experienced in recent months will be sustained.

Continental marked its 50th anniversary in the oil and gas business in 2017. Our leadership team has significant experience with operating in challenging commodity price environments. With our portfolio of high quality assets, we are well-positioned to manage the ongoing challenges and price volatility facing our industry.

For 2018, our primary business strategies will focus on:

- Balancing strong production growth with free cash flow generation;
- Enhancing cash flows and return on capital employed through improvements in operating efficiencies, technical innovations, and optimized completion methods;
- Continuing to exercise disciplined capital spending to maintain financial flexibility and ample liquidity; and
- Improving debt metrics by further reducing outstanding debt using available operating cash flows or proceeds from asset dispositions or joint development arrangements.

Based on an expectation for higher operating cash flows in 2018 in response to improvement in crude oil prices in late 2017 and early 2018, we have increased our planned non-acquisition capital spending for 2018 to $2.3 billion compared to $2.0 billion spent in 2017, with approximately 78% of our 2018 drilling and completion budget focusing on oil-weighted areas in

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the North Dakota Bakken and SCOOP Springer plays. We expect to fund our budgeted spending using cash flows from operations. We may adjust our pace of drilling and development as 2018 market conditions evolve.
For 2018, we plan to operate an average of approximately 21 drilling rigs and 10 completion crews for the year. We expect to spend approximately 52% of our 2018 capital expenditures budget on drilling and completion activities in North Dakota Bakken, 20% in SCOOP, and 14% in STACK. The remaining 14% of our 2018 budget will target other capital expenditures such as leasing and renewals, work-overs, and facilities. See the section below titled Summary of Crude Oil and Natural Gas Properties and Projects for further discussion of our 2018 plans.
Our Business Strategy
Despite ongoing volatility and uncertainty in commodity prices, our business strategy continues to be focused on increasing shareholder value by finding and developing crude oil and natural gas reserves at costs that provide attractive rates of return. The principal elements of this strategy include:
Growing and sustaining a premier portfolio of assets focused on balancing production growth with free cash flow generation. We hold a portfolio of leasehold acreage, drilling opportunities and uncompleted wells in certain premier U.S. resource plays with varying access to crude oil, natural gas, and natural gas liquids. We pursue opportunities to develop our existing properties as well as explore for new resource plays where significant reserves may be economically developed. Our capital programs are designed to allocate investments to projects that provide opportunities to deliver strong production growth while generating cash flows in excess of operating and capital requirements, to work down our large inventory of uncompleted wells, to convert our undeveloped acreage to acreage held by production, and to improve hydrocarbon recoveries and rates of return on capital employed. While our operations have historically focused on the exploration and development of crude oil, we also allocate significant capital to natural gas areas that provide attractive rates of return.
Enhance cash flows and return on capital employed through costs reductions, operating efficiencies, technical innovations, and optimized completions. We continue to manage through the current commodity price environment by focusing on improving operating efficiencies and reducing costs. Our key operating areas are characterized by large acreage positions in select unconventional resource plays with multiple stacked geologic formations that provide repeatable drilling opportunities and resource potential. We operate a significant portion of our wells and leasehold acreage and believe the concentration of our operated assets allows us to leverage our technical expertise and manage the development of our properties to achieve cost reductions through operating efficiencies and economies of scale. We continued to achieve efficiency gains in various aspects of our business in 2017, including additional reductions in spud-to-total depth drilling times and average days to drill horizontal laterals, which has led to reductions in drilling costs in our core areas. In addition to lowering our drilling costs, we also work to enhance cash flows through the use of optimized completion technologies that help improve recoveries and rates of return. These efforts have had a positive impact on the efficiency of our capital deployed in recent years, resulting in significant improvement in the quantity of reserves found and developed per dollar invested.
Maintaining financial flexibility and a strong balance sheet. Maintaining a strong balance sheet, ample liquidity, and financial flexibility are key components of our business strategy. In 2017, we reduced our total debt by $226 million, or 3%, from $6.58 billion at year-end 2016 to $6.35 billion at year-end 2017. We are actively targeting further debt reduction using available cash flows from operations or proceeds from potential sales of non-strategic assets and joint development opportunities and will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry.
Focusing on organic growth through disciplined capital investments. Although we consider various growth opportunities, including property acquisitions, our primary focus is on organic growth through leasing and drilling in our core areas where we can exploit our extensive inventory of repeatable drilling opportunities to achieve attractive rates of return. From January 1, 2015 through December 31, 2017, our proved reserve additions through extensions and discoveries were 743 MMBoe compared with insignificant proved reserve acquisitions during that same period.
Our Business Strengths
We have a number of strengths we believe will help us successfully execute our business strategy, including the following:

Large Acreage Inventory. We held approximately 598,400 net undeveloped acres and 1.19 million net developed acres under lease as of December 31, 2017 concentrated in certain premier U.S. resource plays. We are among the largest leaseholders in the Bakken, SCOOP and STACK plays. Being an early entrant in these plays has allowed us to capture significant acreage positions in core parts of the plays.

Expertise with Horizontal Drilling and Optimized Completion Methods. We have substantial experience with horizontal drilling and optimized completion methods and continue to be among industry leaders in the use of new drilling and completion technologies. We continue to improve drilling and completion efficiencies through the use of multi-well pad drilling in our operating areas. Further, we are among industry leaders in drilling long lateral lengths. We have also been among industry leaders in testing and utilizing optimized completion technologies involving various combinations of fluid types, proppant types and volumes, and stimulation stage spacing to determine optimal methods for improving recoveries and rates of return. We continually refine our drilling and completion techniques in an effort to deliver improved results across our properties.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2017, we operated properties comprising 89% of our total proved reserves. By controlling a significant portion of our operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and completion methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our 9 senior officers have an average of 38 years of oil and gas industry experience.

Financial Position and Liquidity. Currently we have a revolving credit facility with lender commitments totaling $2.75 billion that matures in May 2019. We had approximately $2.65 billion of available borrowing capacity under our credit facility at January 31, 2018 after considering outstanding borrowings and letters of credit.

Our credit facility is unsecured and does not have a borrowing base requirement that is subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants. Downgrades of our credit rating will, however, trigger increases in our credit facility’s interest rates and commitment fees paid on unused borrowing availability under certain circumstances.

Crude Oil and Natural Gas Operations

Proved Reserves

Proved reserves are those quantities of crude 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 renewal is reasonably certain. In connection with the estimation of proved reserves, the term "reasonable certainty" implies a high degree of confidence that the quantities of crude oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reserve engineers and Ryder Scott Company, L.P ("Ryder Scott"), our independent reserve engineers, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps including isopach and structure maps, analogy and statistical analysis, and available downhole, production, seismic, and well test data.

The following table sets forth estimated proved crude oil and natural gas reserves information by reserve category as of December 31, 2017. The standardized measure of our discounted future net cash flows totaled approximately $10.5 billion at December 31, 2017. Our reserve estimates as of December 31, 2017 are based primarily on a reserve report prepared by Ryder Scott. In preparing its report, Ryder Scott evaluated properties representing approximately 96% of our PV-10 and 96% of our total proved reserves as of December 31, 2017. Our internal technical staff evaluated the remaining properties. A copy of Ryder Scott's summary report is included as an exhibit to this Annual Report on Form 10-K.

Our estimated proved reserves and related future net revenues, Standardized Measure and PV-10 at December 31, 2017 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2017 through December 2017, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $51.34 per Bbl for crude oil and $2.98 per MMBtu for natural gas ($47.03 per Bbl for crude oil and $3.00 per Mcf for natural gas adjusted for location and quality differentials).

| | Crude Oil (MBbls) | Natural Gas (MMcf) | Total (MBoe) | PV-10 (1) (in millions) |
|---|---|---|---|---|
| Proved developed producing | 318,291 | 1,697,926 | 601,279 | $7,474.9 |
| Proved developed non-producing | 416 | 1,235 | 622 | 6.4 |
| Proved undeveloped | 322,242 | 2,441,120 | 729,094 | 4,352.2 |
| Total proved reserves | 640,949 | 4,140,281 | 1,330,995 | $11,833.5 |
| Standardized Measure (1) | | | | $10,470.2 |

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately $1.4 billion. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties. We and others in the crude oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific income tax characteristics of such entities. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures for further discussion.

The following table provides additional information regarding our estimated proved crude oil and natural gas reserves by region as of December 31, 2017.

| | Proved Developed | | | Proved Undeveloped | | |
|---|---|---|---|---|---|---|
| | Crude Oil (MBbls) | Natural Gas (MMcf) | Total (MBoe) | Crude Oil (MBbls) | Natural Gas (MMcf) | Total (MBoe) |
| North Region: | | | | | | |
| Bakken field | | | | | | |
| North Dakota Bakken | 217,776 | 472,057 | 296,452 | 212,107 | 517,562 | 298,366 |
| Montana Bakken | 21,503 | 38,480 | 27,916 | 10,385 | 14,412 | 12,787 |
| Red River units | | | | | | |
| Cedar Hills | 28,321 | 4,058 | 28,998 | — | — | — |
| Other Red River units | 2,667 | 16 | 2,668 | — | — | — |
| Other | 110 | 7,469 | 1,356 | — | — | — |
| South Region: | | | | | | |
| SCOOP | 35,333 | 754,820 | 161,136 | 84,828 | 1,474,871 | 330,640 |
| STACK | 12,181 | 407,448 | 80,089 | 14,922 | 434,275 | 87,301 |
| Other | 816 | 14,813 | 3,286 | — | — | — |
| Total | 318,707 | 1,699,161 | 601,901 | 322,242 | 2,441,120 | 729,094 |

The following table provides information regarding changes in total estimated proved reserves for the periods presented.

| | Year Ended December 31, | | |
|---|---|---|---|
| MBoe | 2017 | 2016 | 2015 |
| Proved reserves at beginning of year | 1,274,864 | 1,225,811 | 1,351,091 |
| Revisions of previous estimates | (82,012) | (110,474) | (297,198) |
| Extensions, discoveries and other additions | 240,206 | 249,430 | 253,173 |
| Production | (88,562) | (79,390) | (80,926) |
| Sales of minerals in place | (15,197) | (10,513) | (329) |
| Purchases of minerals in place | 1,696 | — | — |
| Proved reserves at end of year | 1,330,995 | 1,274,864 | 1,225,811 |

Revisions of previous estimates. Revisions represent changes in previous reserve estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices and differentials, operating costs, or development costs.

Given the significant volatility in commodity prices in recent years, and given the uncertainty regarding the timing, magnitude and duration of any price recovery, maintaining a strong balance sheet, ample liquidity, and financial flexibility has become an increasingly important component of our long-term business strategy. In light of our strategy to preserve financial flexibility and minimize the incurrence of new debt, we maintained a disciplined spending approach in 2017 and continued to refine our capital program to focus on areas that provide the greatest opportunities to achieve operating efficiencies and cost reductions, to convert undeveloped acreage to acreage held by production, and to improve hydrocarbon recoveries, cash flows and rates of return using optimized completions. As part of this effort, we shifted a portion of our 2017 spending away from the SCOOP and Bakken plays to areas in the emerging STACK play that offered more advantageous opportunities and rates of return in the 2017 commodity price environment. This shift in strategy coupled with our increased emphasis on balancing capital spending with cash flows altered the timing and extent of our previous development plans in certain areas and resulted in the removal of 41 MMBo and 290 Bcf (totaling 89 MMBoe) of PUD reserves no longer scheduled to be developed within five years from the date of initial booking. These removals do not represent the elimination of recoverable hydrocarbons physically in place. In some instances the removed reserves may be developed in the future in the event of further improvement in commodity prices and an expansion of our capital expenditure budget.

Commodity prices increased on average in 2017 relative to 2016 in response to improving domestic and global supply and demand fundamentals and other factors. The 12-month average first-day-of-the-month price for crude oil increased 20% from $42.75 per Bbl for 2016 to $51.34 per Bbl for 2017, while the 12-month average first-day-of-the-month price for natural gas increased 20% from $2.49 per MMBtu for 2016 to $2.98 per MMBtu for 2017. These changes increased the economic lives of

certain producing properties and caused certain previously uneconomic projects to become economic, which had a favorable impact on the Company’s proved reserve estimates, resulting in upward revisions of 29 MMBo and 78 Bcf (totaling 42 MMBoe) in 2017.
Additionally, changes in anticipated production performance on certain properties resulted in 59 MMBo of downward revisions to crude oil reserves and 173 Bcf of upward revisions to natural gas reserves (netting to 30 MMBoe of downward revisions) in 2017. Further, changes in ownership interests, operating costs, and other factors during the year resulted in 7 MMBo of downward revisions to crude oil reserves and 11 Bcf of upward revisions to natural gas reserves (netting to 5 MMBoe of downward revisions) in 2017.
Extensions, discoveries and other additions. These are additions to our proved reserves that result from (i) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (ii) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions for each of the three years reflected in the table above were primarily due to increases in proved reserves associated with our successful drilling and completion activities in the Bakken, SCOOP and STACK areas. Proved reserve additions from our drilling activities in the Bakken totaled 148 MMBoe, 73 MMBoe and 96 MMBoe for 2017, 2016 and 2015, respectively, while reserve additions in SCOOP totaled 53 MMBoe, 97 MMBoe and 93 MMBoe for 2017, 2016 and 2015, respectively. Additionally, extensions and discoveries were impacted by successful drilling and completion results in the STACK play, resulting in proved reserve additions of 39 MMBoe, 79 MMBoe and 57 MMBoe in 2017, 2016 and 2015, respectively. See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2017 drilling activities. We expect a significant portion of future reserve additions will continue to come from our major development projects in the Bakken, SCOOP and STACK areas.
Sales of minerals in place. These are reductions to proved reserves resulting from the disposition of properties during a period. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 14. Property Dispositions for further discussion of notable dispositions. We may continue to seek opportunities to sell non-strategic properties if and when we have the ability to dispose of such assets at favorable terms.
Purchases of minerals in place. These are additions to proved reserves resulting from the acquisition of properties during a period. We have had no significant acquisitions in the past three years. However, we may participate as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms.
Proved Undeveloped Reserves
All of our PUD reserves at December 31, 2017 are located in the Bakken, SCOOP, and STACK plays, our most active development areas, with those plays comprising 43%, 45%, and 12%, respectively, of our total PUD reserves at year-end 2017. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2017. Our PUD reserves at December 31, 2017 include 70 MMBoe of reserves associated with wells where drilling has occurred but the wells have not been completed or are completed but not producing ("DUC wells"). Our DUC wells are classified as PUD reserves when relatively major expenditures are required to complete and produce from the wells.

| | Crude Oil (MBbls) | Natural Gas (MMcf) | Total (MBoe) |
|---|---|---|---|
| Proved undeveloped reserves at December 31, 2016 | 353,018 | 2,419,198 | 756,218 |
| Revisions of previous estimates | (73,684 ) | (131,306 ) | (95,569 ) |
| Extensions and discoveries | 100,874 | 492,468 | 182,952 |
| Sales of minerals in place | (3,441 ) | (24,870 ) | (7,586 ) |
| Purchases of minerals in place | 149 | 3,009 | 650 |
| Conversion to proved developed reserves | (54,674 ) | (317,379 ) | (107,571) |
| Proved undeveloped reserves at December 31, 2017 | 322,242 | 2,441,120 | 729,094 |

Revisions of previous estimates. During the year ended December 31, 2017, we removed 165 gross (123 net) PUD locations, which resulted in the removal of 41 MMBo and 290 Bcf (totaling 89 MMBoe) of PUD reserves, of which 31 MMBo and 66 Bcf (totaling 42 MMBoe) was related to our Bakken properties and 10 MMBo and 218 Bcf (totaling 46 MMBoe) was related to our SCOOP properties. These removals were due to the aforementioned refinement of our drilling program to place emphasis on areas that provide the greatest opportunities to achieve operating efficiencies and cost reductions, to convert undeveloped acreage to acreage held by production, and to improve hydrocarbon recoveries, cash flows and rates of return using optimized completions. These and other aforementioned factors altered the timing and extent of our previous development plans in certain areas and resulted in the removal of PUD reserves no longer scheduled to be developed within five years of the date of initial booking.

Additionally, increases in average crude oil and natural gas prices in 2017 caused certain previously uneconomic projects to become economic, which resulted in upward PUD reserve revisions of 8 MMBo and 22 Bcf (totaling 11 MMBoe) in 2017. Further, changes in anticipated production performance on producing properties having offsetting PUD locations resulted in 43 MMBo of downward revisions to crude oil PUD reserves and 134 Bcf of upward revisions to natural gas PUD reserves (netting to 20 MMBoe of downward revisions) in 2017. Finally, changes in ownership interests, operating costs, and other factors during the year resulted in 3 MMBo of upward revisions to crude oil PUD reserves and 3 Bcf of upward revisions to natural gas PUD reserves (totaling 3 MMBoe of upward revisions) in 2017.

Extensions and discoveries. Extensions and discoveries were primarily due to increases in PUD reserves associated with our successful drilling activity in the Bakken, SCOOP and STACK areas. PUD reserve additions in the Bakken totaled 86 MMBo and 216 Bcf (totaling 122 MMBoe) in 2017, while SCOOP PUD reserve additions totaled 13 MMBo and 193 Bcf (totaling 45 MMBoe), and STACK PUD reserve additions totaled 2 MMBo and 83 Bcf (totaling 16 MMBoe). See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2017 drilling activities in these areas.

Conversion to proved developed reserves. In 2017, we developed approximately 17% of our PUD locations and 14% of our PUD reserves booked as of December 31, 2016 through the drilling and completion of 300 gross (146 net) development wells at a capital cost of approximately $762 million incurred in 2017. PUD conversions in North Dakota Bakken totaled 49 MMBo and 106 Bcf (totaling 66 MMBoe) in 2017, while STACK PUD conversions totaled 4 MMBo and 130 Bcf (totaling 26 MMBoe) and SCOOP PUD conversions totaled 2 MMBo and 81 Bcf (totaling 15 MMBoe).

Given the continued volatility in crude oil prices during the year, we chose not to significantly advance the development of our oil-weighted properties in the SCOOP play in 2017, instead choosing to defer development capital in that play to future periods when prices become more stable and sustainable. Additionally, we deferred certain well completion activities in North Dakota Bakken in 2017 and our inventory of DUC wells that built up in that play in 2016 was not reduced to the extent originally planned for the year. These factors adversely impacted our conversion of PUD reserves to proved developed reserves in 2017.

At December 31, 2016, we had 95 MMBoe of PUD reserves associated with 279 gross (145 net) operated and non-operated DUC locations at that date. A portion of those locations, representing 18 MMBoe of PUD reserves, were not completed in 2017 and are not reflected as having been converted to proved developed reserves during the year and continue to be reflected as PUD locations at December 31, 2017. If the year-end 2016 DUC wells had been fully completed and converted to proved developed locations in 2017, our 2017 PUD reserve conversion rate of 14% would have been 17%.

Our inventory of DUC wells classified as PUDs total 278 gross (105 net) operated and non-operated locations at December 31, 2017, representing 70 MMBoe, or 10%, of our PUD reserves. The following table summarizes 2017 activity associated with DUC wells that are classified as PUD reserves.

| | DUC Wells | | |
|---|---|---|---|
| | Gross | Net | PUD Reserves (MBoe) |
| DUC wells at December 31, 2016 | 279 | 145 | 95,272 |
| Wells converted to proved developed reserves | (203) | (110) | (75,274) |
| Wells added | 209 | 72 | 51,306 |
| Revisions | (7) | (2) | (1,707) |
| DUC wells at December 31, 2017 | 278 | 105 | 69,597 |

Development plans. We have acquired substantial leasehold positions in the Bakken, SCOOP and STACK plays. Our drilling programs to date in those areas have focused on proving our undeveloped leasehold acreage through strategic drilling, thereby increasing the amount of leasehold acreage in the secondary term of the lease with no further drilling obligations (i.e., categorized as held by production) and resulting in a reduced amount of leasehold acreage in the primary term of the lease. While we may opportunistically drill strategic exploratory wells, a substantial portion of our future capital expenditures will be focused on developing our PUD locations, including our drilled but not completed locations. The costs to drill our uncompleted wells were incurred prior to December 31, 2017 and only the remaining completion costs are included in future development plans.

Estimated future development costs relating to the development of PUD reserves are projected to be approximately $1.0 billion in 2018 (44% of total capital budget), $1.5 billion in 2019, $1.7 billion in 2020, $1.5 billion in 2021, and $0.7 billion in 2022. These capital expenditure projections are reflective of the current commodity price environment and have been established based on an expectation of drilling and completion costs, available cash flows, and borrowing capacity. Development of our existing PUD reserves at December 31, 2017, including those associated with DUC wells, is expected to occur within five years of the date of initial booking of the PUDs. PUD reserves not expected to be developed within five years of initial booking because of changes in business strategy, depressed commodity prices, or for other reasons have been removed from our reserves at December 31, 2017. We had no PUD reserves at December 31, 2017 that remain undeveloped beyond five years from the date of initial booking.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimation Process

Ryder Scott, our independent reserves evaluation consulting firm, estimated, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC, 96% of our PV-10 and 96% of our total proved reserves as of December 31, 2017 included in this Form 10-K. The Ryder Scott technical personnel responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Refer to Exhibit 99 included with this Form 10-K for further discussion of the qualifications of Ryder Scott personnel.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserves engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team is in contact regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott’s preparation of the year-end reserves estimates. Proved reserves information is reviewed by our Audit Committee with representatives of Ryder Scott and by our internal technical staff before the information is filed with the SEC on Form 10-K. Additionally, certain members of our senior management review and approve the Ryder Scott reserves report and on a semi-annual basis review any internal proved reserves estimates.

Our Vice President—Corporate Reserves is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering, an MBA in Finance and 33 years of industry experience with positions of increasing responsibility in operations, acquisitions, engineering and evaluations. He has worked in the area of reserves and reservoir engineering most of his career and is a member of the Society of Petroleum Engineers. The Vice President—Corporate Reserves reports directly to our Vice Chairman of Strategic Growth Initiatives. The reserves estimates are reviewed and approved by the Company's President and certain other members of senior management.

Proved Reserve, Standardized Measure, and PV-10 Sensitivities

Our year-end 2017 proved reserve, Standardized Measure, and PV-10 estimates were prepared using 2017 average first-day-of-the-month prices of $51.34 per Bbl for crude oil and $2.98 per MMBtu for natural gas ($47.03 per Bbl for crude oil and $3.00 per Mcf for natural gas adjusted for location and quality differentials). Actual future prices may be materially higher or lower than those used in our year-end estimates.

Provided below are sensitivities illustrating the potential impact on our estimated proved reserves, Standardized Measure, and PV-10 at December 31, 2017 under different commodity price scenarios for crude oil and natural gas. In these sensitivities, all factors other than the commodity price assumption have been held constant for each well. These sensitivities demonstrate the impact that changing commodity prices may have on estimated proved reserves, Standardized Measure, and PV-10 and there is no assurance these outcomes will be realized.

The crude oil price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under various crude oil price scenarios, with natural gas prices being held constant at the 2017 average first-day-of-the-month price of $2.98 per MMBtu.

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The natural gas price sensitivities provided below show the impact on proved reserves, Standardized Measure, and PV-10 under various natural gas price scenarios, with crude oil prices being held constant at the 2017 average first-day-of-the-month price of $51.34 per Bbl.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acres by region as of December 31, 2017:

| | Developed acres | | Undeveloped acres | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| North Region: | | | | | | |
| Bakken field | | | | | | |
| North Dakota Bakken | 951,645 | 556,044 | 147,513 | 90,288 | 1,099,158 | 646,332 |
| Montana Bakken | 170,899 | 137,594 | 30,059 | 17,601 | 200,958 | 155,195 |
| Red River units | 158,967 | 139,418 | 26,719 | 13,124 | 185,686 | 152,542 |
| Other | 102,542 | 66,399 | 94,454 | 68,597 | 196,996 | 134,996 |
| South Region: | | | | | | |
| SCOOP | 230,799 | 133,756 | 260,257 | 143,116 | 491,056 | 276,872 |
| STACK | 211,836 | 118,563 | 177,563 | 93,846 | 389,399 | 212,409 |
| Other | 67,734 | 32,928 | 71,250 | 33,067 | 138,984 | 65,995 |
| East Region | 449 | 404 | 161,935 | 138,799 | 162,384 | 139,203 |
| Total | 1,894,871 | 1,185,106 | 969,750 | 598,438 | 2,864,621 | 1,783,544 |

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2017 scheduled to expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates or the leases are renewed.

| | 2018 | | 2019 | | 2020 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| North Region: | | | | | | |
| Bakken field | | | | | | |
| North Dakota Bakken | 20,557 | 12,742 | 2,890 | 1,544 | 29,318 | 20,170 |
| Montana Bakken | 14,713 | 9,489 | 400 | 400 | — | — |
| Red River units | 5,617 | 3,318 | 2,879 | 1,365 | — | — |
| Other | 9,264 | 5,849 | 20,097 | 13,877 | 4,520 | 1,795 |
| South Region: | | | | | | |
| SCOOP | 75,650 | 41,718 | 68,307 | 37,774 | 51,635 | 31,767 |
| STACK | 40,196 | 22,346 | 72,528 | 38,450 | 31,777 | 17,782 |
| Other | 1,840 | 504 | 28,258 | 12,251 | 23,513 | 11,986 |
| East Region | 6,947 | 6,292 | 55,347 | 40,336 | 11,728 | 10,164 |
| Total | 174,784 | 102,258 | 250,706 | 145,997 | 152,491 | 93,664 |

Drilling Activity

During the three years ended December 31, 2017, we drilled and completed exploratory and development wells as set forth in the table below:

| | 2017 | | 2016 | | 2015 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Exploratory wells: | | | | | | |
| Crude oil | 34 | 9.0 | 39 | 11.4 | 28 | 19.8 |
| Natural gas | 9 | 3.1 | 15 | 4.2 | 19 | 1.4 |
| Dry holes | — | — | — | — | 1 | 1.0 |
| Total exploratory wells | 43 | 12.1 | 54 | 15.6 | 48 | 22.2 |
| Development wells: | | | | | | |
| Crude oil | 474 | 175.4 | 245 | 54.7 | 707 | 215.5 |
| Natural gas | 91 | 26.8 | 66 | 21.6 | 142 | 32.8 |
| Dry holes | — | — | — | — | — | — |
| Total development wells | 565 | 202.2 | 311 | 76.3 | 849 | 248.3 |
| Total wells | 608 | 214.3 | 365 | 91.9 | 897 | 270.5 |

As of December 31, 2017, there were 475 gross (179 net) operated and non-operated wells that have been spud and are in the process of drilling, completing or waiting on completion.

Summary of Crude Oil and Natural Gas Properties and Projects

In the following discussion, we review our budgeted number of wells and capital expenditures for 2018 in our key operating areas. Our 2018 capital budget has been set based on an expectation of available cash flows in order to minimize the incurrence of new debt. If cash flows are materially impacted by a decline in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability of our revolving credit facility if needed to fund our operations. Conversely, higher cash flows resulting from an increase in commodity prices could result in increased capital expenditures.

The following table provides information regarding well counts and 2018 budgeted capital expenditures by operating area.

| | 2018 Plan | | |
|---|---|---|---|
| | Gross wells (1) | Net wells (1) | Capital expenditures (in millions) (2) |
| North Region: | | | |
| Bakken | 415 | 143 | $ 1,193 |
| South Region: | | | |
| SCOOP | 160 | 44 | 465 |
| STACK and Other | 181 | 38 | 330 |
| Total exploration and development drilling | 756 | 225 | $ 1,988 |
| Land | | | 132 |
| Capital facilities, workovers and other corporate assets | | | 168 |
| Seismic | | | 12 |
| Total 2018 capital budget, excluding acquisitions | | | $ 2,300 |

(1) Represents operated and non-operated wells expected to have first production in 2018.

(2) Represents total capital expenditures for operated and non-operated wells expected to have first production in 2018 and wells spud that will be in the process of drilling, completing or waiting on completion as of year-end 2018.

North Region

Our properties in the North region represented 50% of our total proved reserves as of December 31, 2017 and 61% of our average daily Boe production for the fourth quarter of 2017. Our average daily production from such properties was 175,563 Boe per day for the fourth quarter of 2017, an increase of 48% from the comparable 2016 period due to increased drilling and completion activities in 2017. Our principal producing properties in the North region are primarily located in the Bakken field.

Bakken Field

The Bakken field of North Dakota and Montana is one of the premier crude oil resource plays in the United States. We are a leading producer, leasehold owner and operator in the Bakken. As of December 31, 2017, we controlled one of the largest leasehold positions in the Bakken with approximately 1.3 million gross (801,500 net) acres under lease. Our total Bakken production averaged 165,598 Boe per day for the fourth quarter of 2017, up 58% from the 2016 fourth quarter. For the year ended December 31, 2017, our average daily Bakken production increased 12% over 2016. We increased our drilling and well completion activities in the Bakken in 2017, particularly in the second half of the year, in response to stabilization and improvement in crude oil prices. In 2017, we participated in the drilling and completion of 370 gross (145 net) wells in the Bakken compared to 192 gross (38 net) wells completed in 2016. Our 2017 activities in the Bakken focused on development of de-risked, higher rate-of-return areas in core parts of North Dakota and the testing of various optimized completion methods aimed at improving crude oil recoveries and rates of return.

Our Bakken properties represented 48% of our total proved reserves at December 31, 2017 and 58% of our average daily Boe production for the 2017 fourth quarter. Our total proved Bakken field reserves as of December 31, 2017 were 636 MMBoe, an increase of 7% compared to December 31, 2016 due to reserves added from our drilling program, continued improvement in recoveries driven by advances in optimized completion designs, and upward reserve revisions prompted by higher commodity prices in 2017. Our inventory of proved undeveloped drilling locations in the Bakken totaled 1,252 gross (656 net) wells as of December 31, 2017.

In response to the stabilization and improvement in crude oil prices in late 2017 and early 2018 we plan to increase our activities in North Dakota Bakken in 2018 relative to 2017. In 2018, we plan to invest approximately $1.19 billion in the play, which includes $413 million for the completion and initiation of production on operated Bakken wells that were drilled but not completed as of year-end 2017. We plan to operate, on average, six rigs in North Dakota Bakken throughout 2018, an increase from four rigs as of December 31, 2017. Additionally, we plan to use, on average, six to seven well completion crews in North Dakota Bakken throughout 2018, consistent with our current activity levels. Our 2018 drilling and completion activities will focus on core parts of North Dakota Bakken that provide opportunities to improve capital efficiency, reduce finding and development costs, and improve recoveries and rates of return.

South Region

Our properties in the South region represented 50% of our total proved reserves as of December 31, 2017 and 39% of our average daily Boe production for the fourth quarter of 2017. For the 2017 fourth quarter, our average daily production from such properties was 111,422 Boe per day, an increase of 22% from the comparable period in 2016. Our principal producing properties in the South region are located in the SCOOP and STACK areas of Oklahoma.

SCOOP

The SCOOP play currently extends across Garvin, Grady, Stephens, Carter, McClain and Love counties in Oklahoma and contains crude oil and condensate-rich fairways as delineated by numerous industry wells. We are a leading producer, leasehold owner and operator in the SCOOP play. As of December 31, 2017, we controlled one of the largest leasehold positions in SCOOP with approximately 491,100 gross (276,900 net) acres under lease.

Our SCOOP leasehold has the potential to contain hydrocarbons from a variety of conventional and unconventional reservoirs overlying and underlying the Woodford formation in Oklahoma. In recent years, our drilling activities have resulted in the vertical expansion of our SCOOP Woodford position with discoveries of the SCOOP Springer and Sycamore formations, which are located directly above the Woodford formation. Located in the heart of our SCOOP acreage, our Springer and Sycamore positions supplement our Woodford leasehold and expand our resource potential and inventory in the play.

We engaged in limited drilling and completion activities in SCOOP in 2017, choosing instead to allocate capital to other areas that offered more advantageous opportunities and rates of return. Our 2017 activities in SCOOP focused on continued vertical and horizontal expansion of the productive extent and hydrocarbon content of the play and working to determine optimum well spacing, well patterns, and completion methods for future development.

SCOOP represented 37% of our total proved reserves as of December 31, 2017 and 22% of our average daily Boe production for the fourth quarter of 2017. Production in SCOOP averaged 62,242 Boe per day during the fourth quarter of 2017, down 2% compared to the 2016 fourth quarter. For the year ended December 31, 2017, average daily production in SCOOP decreased 7% compared to 2016, reflecting natural declines in production and limited drilling and completion activities in 2017. We participated in the drilling and completion of 77 gross (20 net) wells in SCOOP during 2017 compared to 72 gross (28 net) wells in 2016. Proved reserves in SCOOP totaled 492 MMBoe as of December 31, 2017, an increase of 4% compared to December 31, 2016 due to reserves added from our drilling program, continued improvement in recoveries driven by advances in optimized completion designs, and upward reserve revisions prompted by higher commodity prices in 2017. Our inventory of proved undeveloped drilling locations in SCOOP totaled 336 gross (230 net) wells as of December 31, 2017.

In 2018, we plan to invest approximately $465 million to drill, complete and initiate production on 160 gross (44 net) operated and non-operated wells in the SCOOP play. We plan to average approximately seven operated rigs and one completion crew in SCOOP throughout 2018, an increase from five rigs as of December 31, 2017. Our 2018 drilling program will continue to focus on expanding the known productive extent of the SCOOP Woodford, Springer and Sycamore formations, while focusing on areas that provide opportunities for converting undeveloped acreage to acreage held by production, increasing capital efficiency, reducing finding and development costs, and improving rates of return.

STACK

STACK is a significant resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec, Osage and Woodford formations. As of December 31, 2017, we controlled one of the largest leasehold positions in STACK with approximately 389,400 gross (212,400 net) acres under lease. A significant portion of our STACK acreage is located in over-pressured portions of Blaine, Dewey and Custer counties of Oklahoma where we believe the reservoirs are typically thicker and deliver superior production rates relative to normal-pressured areas of the STACK petroleum system.

Building on early success achieved from our initial STACK drilling activities in mid-2015, we significantly increased our leasing and drilling activities in the play in 2016 and 2017. Our 2017 activities focused on pilot density drilling to expand our understanding of the productive extent and hydrocarbon content of the play and to help determine optimum well spacing, well patterns, and completion methods for future development.

Through our 2016 and 2017 activities in STACK, we have successfully tested productive zones in the play, applied optimized completions to improve recoveries, demonstrated repeatability of results, reduced drilling times, reduced well costs, and de-risked a sizeable portion of our acreage in the play. Due to the success of these efforts, STACK has become another significant growth platform for us and is expected to be an important contributor to our long-term growth. To facilitate future development of our STACK acreage, we continue to increase our water recycling and distribution capabilities in the play. Additionally, we continue to increase our access to gathering and takeaway capacity to handle crude oil and natural gas production expected from future development of the play.

Our STACK properties represented 13% of our total proved reserves as of December 31, 2017 and 17% of our average daily Boe production for the fourth quarter of 2017. Production in STACK increased to an average rate of 47,914 Boe per day during the fourth quarter of 2017, up 96% over the 2016 fourth quarter due to additional drilling and completion activity resulting from our drilling program. For the year ended December 31, 2017, average daily production in STACK grew 113% over 2016. We participated in the drilling and completion of 160 gross (49 net) wells in STACK during 2017 compared to 97 gross (26 net) wells in 2016. Proved reserves increased 4% year-over-year to 167 MMBoe as of December 31, 2017 due to reserves added from our drilling program, continued improvement in recoveries driven by advances in optimized completion designs, and upward reserve revisions prompted by higher commodity prices in 2017. Our inventory of proved undeveloped drilling locations in STACK totaled 195 gross (90 net) wells as of December 31, 2017.

In 2018, we plan to invest approximately $317 million to drill, complete and initiate production on 180 gross (37 net) operated and non-operated wells in STACK. We plan to average approximately eight operated rigs in STACK throughout 2018 compared to nine rigs as of December 31, 2017. Additionally, we plan to use, on average, three completion crews in STACK throughout 2018 compared to five crews as of December 31, 2017. Our 2018 activities will focus on delineating and de-risking our acreage, expanding the known productive extent of the play through the completion of new density test projects, monitoring production from optimized completions, and continued refinement of our geologic and economic models in the area.

Production and Price History

The following table sets forth information concerning our production results, average sales prices and production costs for the years ended December 31, 2017, 2016 and 2015 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2017 (North Dakota Bakken and SCOOP). Information for the STACK field is also presented.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Net production volumes: | | | |
| Crude oil (MBbls) | | | |
| North Dakota Bakken | 35,964 | 31,723 | 37,539 |
| SCOOP | 5,726 | 6,807 | 7,198 |
| STACK | 3,166 | 1,552 | 245 |
| Total Company | 50,536 | 46,850 | 53,517 |
| Natural gas (MMcf) | | | |
| North Dakota Bakken | 59,232 | 50,532 | 47,425 |
| SCOOP | 98,563 | 102,032 | 91,687 |
| STACK | 60,325 | 27,983 | 10,704 |
| Total Company | 228,159 | 195,240 | 164,454 |
| Crude oil equivalents (MBoe) | | | |
| North Dakota Bakken | 45,836 | 40,145 | 45,444 |
| SCOOP | 22,153 | 23,813 | 22,479 |
| STACK | 13,220 | 6,216 | 2,029 |
| Total Company | 88,562 | 79,390 | 80,926 |
| Average sales prices: | | | |
| Crude oil ($/Bbl) | | | |
| North Dakota Bakken | $45.21 | $ 34.33 | $ 39.76 |
| SCOOP | 47.96 | 38.87 | 43.98 |
| STACK | 49.68 | 41.95 | 41.23 |
| Total Company | 45.70 | 35.51 | 40.50 |
| Natural gas ($/Mcf) | | | |
| North Dakota Bakken | $2.97 | $ 1.05 | $ 2.34 |
| SCOOP | 3.26 | 2.24 | 2.39 |
| STACK | 2.43 | 1.87 | 2.06 |
| Total Company | 2.93 | 1.87 | 2.31 |
| Crude oil equivalents ($/Boe) | | | |
| North Dakota Bakken | $39.32 | $ 28.45 | $ 35.29 |
| SCOOP | 26.93 | 20.71 | 23.81 |
| STACK | 22.89 | 18.88 | 15.87 |
| Total Company | 33.65 | 25.55 | 31.48 |
| Average costs per Boe: | | | |
| Production expenses ($/Boe) | | | |
| North Dakota Bakken | $4.40 | $ 4.59 | $ 4.79 |
| SCOOP | 1.01 | 1.13 | 1.10 |
| STACK | 1.22 | 1.00 | 3.52 |
| Total Company | 3.66 | 3.65 | 4.30 |
| Production taxes ($/Boe) | $2.35 | $ 1.79 | $ 2.47 |
| General and administrative expenses ($/Boe) | $2.16 | $ 2.14 | $ 2.34 |
| DD&A expense ($/Boe) | $18.89 | $ 21.54 | $ 21.57 |

The following table sets forth information regarding our average daily production by region for the fourth quarter of 2017:

| | Fourth Quarter 2017 Daily Production | | |
|---|---|---|---|
| | Crude Oil (Bbls per day) | Natural Gas (Mcf per day) | Total (Boe per day) |
| North Region: | | | |
| Bakken field | | | |
| North Dakota Bakken | 124,811 | 202,975 | 158,640 |
| Montana Bakken | 5,497 | 8,761 | 6,958 |
| Red River units | | | |
| Cedar Hills | 6,830 | 1,154 | 7,022 |
| Other Red River units | 2,073 | 2,410 | 2,475 |
| Other | 82 | 2,318 | 468 |
| South Region: | | | |
| SCOOP | 14,551 | 286,148 | 62,242 |
| STACK | 13,788 | 204,754 | 47,914 |
| Other | 434 | 4,998 | 1,266 |
| Total | 168,066 | 713,518 | 286,985 |

Productive Wells

Gross wells represent the number of wells in which we own a working interest and net wells represent the total of our fractional working interests owned in gross wells. The following table presents the total gross and net productive wells by region and by crude oil or natural gas completion as of December 31, 2017. One or more completions in the same well bore are counted as one well.

| | Crude Oil Wells | | Natural Gas Wells | | Total Wells | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| North Region: | | | | | | |
| Bakken field | | | | | | |
| North Dakota Bakken | 4,083 | 1,313 | — | — | 4,083 | 1,313 |
| Montana Bakken | 401 | 263 | — | — | 401 | 263 |
| Red River units | | | | | | |
| Cedar Hills | 135 | 130 | — | — | 135 | 130 |
| Other Red River units | 131 | 117 | — | — | 131 | 117 |
| Other | 8 | 4 | 18 | 4 | 26 | 8 |
| South Region: | | | | | | |
| SCOOP | 248 | 145 | 372 | 115 | 620 | 260 |
| STACK | 172 | 62 | 282 | 98 | 454 | 160 |
| Other | 139 | 110 | 167 | 65 | 306 | 175 |
| Total | 5,317 | 2,144 | 839 | 282 | 6,156 | 2,426 |

Title to Properties

As is customary in the crude oil and natural gas industry, upon initiation of acquiring oil and gas leases covering fee mineral interests on undeveloped lands which do not have associated proved reserves, contract landmen conduct a title examination of courthouse records and production databases to determine fee mineral ownership and availability. Title, lease forms, and final terms are reviewed and approved by Company landmen prior to consummation.

For acquisitions from third parties, whether lands are producing crude oil and natural gas or non-producing, Company and contract landmen perform title examinations at applicable courthouses, obtain physical well site inspections, and examine the seller’s internal records (land, legal, operational, production, environmental, well, marketing and accounting) upon execution of a mutually acceptable purchase and sale agreement. We may also procure an acquisition title opinion from outside legal counsel on higher value properties.

Prior to the commencement of drilling operations, we procure an original title opinion, or supplement an existing title opinion, from outside legal counsel and perform curative work to satisfy requirements pertaining to material title defects, if any. We will not approve commencement of drilling operations until we have cured material title defects pertaining to the Company's interest.

We have procured title opinions and cured material defects as to Company interests on substantially all of our producing properties and believe we have at least defensible title to our producing properties in accordance with standards generally accepted in the crude oil and natural gas industry. Our crude oil and natural gas properties are subject to customary royalty and leasehold burdens which do not materially interfere with the use of the properties or affect our carrying value of such properties.

Marketing and Major Customers

Most of our operated crude oil production is sold to either crude oil refining companies or midstream marketing companies at major market centers. Other operated production not sold at major market centers is sold at the lease. In the Bakken, SCOOP and STACK areas we have significant volumes of production directly connected to pipeline gathering systems, with the remaining balance of production being primarily transported by truck. Additionally in the Bakken, a portion of our production is sold to counterparties that are connected to rail delivery systems. Where directly marketed crude oil is transported by truck, it is delivered to a point on a pipeline system for further delivery, or is delivered directly to a refinery. Where crude oil is sold at the lease the sale is complete at that point. Our share of crude oil production from non-operated properties is marketed at the discretion of the operators.

The majority of our operated natural gas production is sold at our lease locations to midstream purchasers under term contracts. These contracts include multi-year term agreements, many with acreage dedication. Some of our contracts allow us the flexibility to accept, as partial payment for our sale of gas in the field, an "in-kind" volume of processed gas at the tailgate of the midstream purchaser's processing plant. When we elect to do so, we transport this processed gas to a downstream market where it is sold. Sales at these downstream markets are mostly under monthly interruptible packaged volume deals, short term seasonal packages, and long term multi-year contracts. We continue to develop relationships and have the potential to enter into additional contracts with end-use customers, including utilities, industrial users, and liquefied natural gas exporters, for sale of gas we elect to take in-kind in lieu of cash for our leasehold sales. Our share of natural gas production from non-operated properties is generally marketed at the discretion of the operators.

Our marketing of crude oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, see Part I, Item 1A. Risk factors—Our business depends on crude oil and natural gas transportation, processing and refining facilities, most of which are owned by third parties.

For the year ended December 31, 2017, sales to BP p.l.c. and affiliates and Phillips 66 and affiliates accounted for approximately 11% and 11%, respectively, of our total crude oil and natural gas revenues. No other purchaser accounted for more than 10% of our total crude oil and natural gas revenues for 2017. The loss of any single purchaser will not have a material adverse effect on our operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

Competition

We operate in a highly competitive environment for acquiring properties, marketing crude oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive crude oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions economically in a highly competitive environment. In addition, as a result of the significant decrease in commodity prices in recent years, the number of providers of materials and services has decreased in the regions where we operate. As a result, the likelihood of experiencing competition and shortages of materials and services may be further increased in connection with any period of commodity price recovery.

Regulation of the Crude Oil and Natural Gas Industry

Our operations are conducted onshore almost entirely in the United States. The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. Laws, rules, regulations, policies, and interpretations affecting our industry have been and are pervasive with the imposition of new or increased requirements on us and other industry participants. These laws, regulations and other requirements often carry substantial penalties for failure to comply and may have a significant effect on the exploration, development, production or sale of crude oil and natural gas and increase the cost of doing business and affect profitability. In addition, because public policy changes affecting the crude oil and natural gas industry are commonplace and because laws, rules and regulations may be enacted, amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws, rules and regulations. We do not expect any future legislative or regulatory initiatives will affect us in a manner materially different than they would affect our similarly situated competitors.

The following is a discussion of significant laws, rules and regulations, as amended from time to time, that may affect us in the areas in which we operate.

Regulation of sales and transportation of crude oil and natural gas liquids

Sales of crude oil and natural gas liquids (“NGLs”) or condensate in the United States are not currently subject to price controls and are made at negotiated prices. Nevertheless, the U.S. Congress could enact price controls in the future. Beginning in the 1970s, the United States regulated the exportation of petroleum and petroleum products, which restricted the markets for these commodities and affected sales prices. However, in December 2015 the U.S. Congress passed a legislative bill eliminating the export restrictions beginning in January 2016.

With regard to our physical sales of crude oil and any derivative instruments relating to crude oil, we are required to comply with anti-market manipulation laws and related regulations enforced by the Federal Trade Commission (“FTC”) and the Commodity Futures Trading Commission (“CFTC”). See the discussion below of “Other Federal Laws and Regulations Affecting Our Industry—FTC and CFTC Market Manipulation Rules.” If we violate the anti-market manipulation laws and regulations, we could be subject to substantial penalties and related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Our sales of crude oil are affected by the availability, terms and costs of transportation. The transportation of crude oil and NGLs, as well as other liquid products, is subject to rate and access regulation. The Federal Energy Regulatory Commission (“FERC”) regulates interstate crude oil and NGL pipeline transportation rates under the Interstate Commerce Act and the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. In general, pipeline rates must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. Oil and other liquid pipeline rates are often cost-based, although some pipeline charges today are based on historical rates adjusted for inflation and other factors, and other charges may result from settlement rates agreed to by all shippers or market-based rates, which are permitted in certain circumstances. FERC or interested persons may challenge existing or changed rates or services. Intrastate crude oil and NGL pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state. As the interstate and intrastate transportation rates we pay are generally applicable to all comparable shippers, the regulation of intrastate transportation rates will not affect us in a way that materially differs from the effect on our similarly situated competitors.

Further, interstate pipelines and intrastate common carrier pipelines must provide service on an equitable basis and offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When such pipelines operate at full capacity we are subject to proration provisions, which are described in the pipelines’ published tariffs. We generally will have access to crude oil pipeline transportation services to the same extent as our similarly situated competitors.

We transport operated crude oil production from our North region to market centers using primarily a combination of pipeline and rail transportation facilities owned and operated by third parties. Approximately 6% of such production was shipped by rail in December 2017, with the remainder being shipped primarily by pipeline. The U.S. Department of Transportation’s (“U.S. DOT”) Pipeline and Hazardous Materials Safety Administration (“PHMSA”) establishes safety regulations relating to transportation of crude oil by rail and pipeline. Third party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the U.S. DOT, the Federal Railroad Administration ("FRA"), the U.S. Occupational Safety and Health Administration ("OSHA"), and other federal regulatory agencies. Additionally, various state and local agencies have jurisdiction over disposal of hazardous waste and regulate movement of hazardous materials if not preempted by federal law.

In 2008, the U.S. Congress passed the Rail Safety and Improvement Act, which implemented regulations governing different areas related to railroad safety. Subsequently, the FRA and PHMSA have taken several actions related to the transport of crude oil, including but not limited to: issuing an order requiring testing, classification and handling of crude oil as a hazardous material; requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas; issuing safety advisories, alerts, emergency orders and regulatory updates; conducting special unannounced inspections; issuing rules to enhance tank car standards for certain trains carrying crude oil and ethanol; and reaching agreement with the railroad industry on a series of voluntary actions it can take to improve safety. In May 2014 the U.S. DOT issued an order requiring all railroads operating trains containing large amounts of Bakken crude oil to notify state emergency response commissions about the operation of such trains through their states. The order requires each railroad operating trains containing more than 1,000,000 gallons of Bakken crude oil, or approximately 35 tank cars, in a particular state to provide the state with notification regarding the volumes of Bakken crude oil being transported, frequencies of anticipated train traffic and the route through which Bakken crude oil will be transported. Also in May 2014, the FRA and PHMSA issued a safety advisory to the rail industry strongly recommending the use of tank cars with the highest level of integrity in their fleet when transporting Bakken crude oil. In May 2015, PHMSA published a final rule which requires, among other things, enhanced tank car standards for new and existing tank cars, a classification and testing program for crude oil, and a requirement that older DOT-111 tank cars be retrofitted to comply with new tank car design standards in accordance with a specified timeline beginning as early as January 1, 2018. However, in December 2017 PHMSA announced it would initiate a rulemaking to rescind the May 2015 rule's requirements regarding electronically controlled pneumatic brakes. In August 2016, PHMSA released a final rule mandating a phase-out schedule for all DOT-111 tank cars used to transport Class 3 flammable liquids between 2018 and 2029. Separately, in July 2016 PHMSA proposed a new rule to expand the applicability of comprehensive oil spill response plans so that any railroad transporting a single train carrying 20 or more loaded tank cars of liquid petroleum oil in a continuous block or a single train carrying 35 or more loaded tank cars of liquid petroleum oil throughout the train must have a current, comprehensive, written plan. Issuance of the final rule remains pending.

We do not own or operate rail transportation facilities or rail cars; however, regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at market centers throughout the United States, which could have a material adverse effect on our financial condition, results of operations and cash flows. We do not expect such regulations will affect us in a materially different way than similarly situated competitors.

In June 2016 the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act (“PIPES Act”) was signed into law. The PIPES Act extends PHMSA’s safety authority through 2019 and includes provisions on advancing the safe transportation of energy commodities and other hazardous materials. The PIPES Act includes provisions aimed at increasing inspection requirements for certain underwater crude oil pipelines; improving protection of coastal areas by designating them as environmentally sensitive to pipeline failures; setting minimum safety standards for underground natural gas storage facilities, and promoting better use of data and technology to prevent damage and improve safety of pipeline systems, among other things. PHMSA published a final rule in January 2017 expanding integrity management and reporting requirements for certain hazardous liquid pipelines and gathering lines; however, implementation of the final rule was stayed following the change in U.S. Presidential Administrations. The final rule is expected to be published in the federal register during the first quarter of 2018. We do not expect such regulations will affect us in a materially different way than similarly situated competitors.

Pipeline regulations exist at the state level as well. In December 2014 the North Dakota Industrial Commission (“NDIC”) introduced rules designed to reduce the potential flammability of crude oil produced from the Bakken petroleum system (the Bakken, Three Forks, and Sanish Pool formations) before it is loaded and transported on railcars. The rules became effective in April 2015 and outline a series of standards for pressure and temperature for production facilities to follow in order to separate certain liquids and gases from the crude oil prior to transport. These rules do not affect us in a way that materially differs from our similarly situated competitors.

Regulation of sales and transportation of natural gas

In 1989, the U.S. Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. The FERC, which has the authority under the Natural Gas Act (“NGA”) to regulate prices, terms, and conditions for the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to FERC regulation, except interstate pipelines, to resell natural gas at market prices. However, either the U.S. Congress or the FERC (with respect to the resale of gas in interstate commerce) could re-impose price controls in the future. The U.S. Department of Energy ("U.S. DOE") regulates the terms and conditions for the exportation and importation of natural gas (including liquefied natural gas or "LNG"). U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a Free Trade Agreement ("FTA") with the United States providing for national treatment of trade in natural gas; however, the U.S. DOE's regulation of imports and exports from and to countries without an FTA is more comprehensive. The FERC also regulates the construction and operation of import and export facilities, including LNG terminals. Regulation of imports and exports and related facilities may materially affect natural gas markets and sales prices.

The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the Natural Gas Policy Act of 1978 ("NGPA"), which affects the marketing of natural gas we produce, as well as revenues we receive for sales of our natural gas. The FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated open access policies are necessary to improve the competitive structure of the natural gas pipeline industry and to create a regulatory framework to put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. The FERC has issued a series of orders to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage services on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry. We cannot provide any assurance the pro-competitive regulatory approach established by the FERC will continue. However, we do not believe any action taken by FERC will affect us in a materially different way than similarly situated natural gas producers.

With regard to our physical sales of natural gas and derivative instruments relating to natural gas, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and the CFTC. See the discussion below of "Other Federal Laws and Regulations Affecting Our Industry—FTC and CFTC Market Manipulation Rules." If we violate the anti-market manipulation laws and regulations, we could be subject to substantial penalties and related third-party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to various FERC orders, we may be required to submit reports to the FERC for some of our operations. See the discussion below of "Other Federal Laws and Regulations Affecting Our Industry—FERC Market Transparency and Reporting Rules."

Gathering service, which occurs upstream of jurisdictional transmission services, is generally regulated by the states. Although its policies on gathering systems have varied in the past, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the potential to increase our costs of moving natural gas to point of sale locations. State regulation of natural gas gathering facilities generally includes various safety, environmental, and in some circumstances, equitable take requirements. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels in the future. We cannot predict what effect, if any, such changes may have on us, but the natural gas industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes, including changes in the interpretation of existing requirements or programs to implement those requirements. We do not believe we would be affected by any such regulatory changes in a materially different way than our similarly situated competitors.

Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas we produce, as well as the revenues we receive for sales of our natural gas. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers on a comparable basis, the regulation of intrastate natural gas transportation in states in which we operate and ship natural gas on an intrastate basis will not affect us in a way that materially differs from our similarly situated competitors.

Regulation of production

The production of crude oil and natural gas is regulated by a wide range of federal, state and local statutes, rules, orders and regulations, which require, among other matters, permits for drilling operations, drilling bonds and reports concerning operations. Each of the states where we own and operate properties have regulations governing conservation, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum allowable rates of production from crude oil and natural gas wells, the regulation of well spacing, the plugging and abandonment of wells, and limitations or prohibitions on the venting or flaring of natural gas. These regulations limit the amount of crude oil and natural gas we can produce from our wells and the number of wells and locations we can drill, although we can and do apply for exceptions to such regulations or to have reductions

in well spacing. Moreover, each state generally imposes a production, severance or excise tax on the production and sale of crude oil, natural gas and natural gas liquids within its jurisdiction.
The failure to comply with these rules and regulations can result in substantial penalties. Our similarly situated competitors are generally subject to the same statutes, regulatory requirements and restrictions.

Other federal laws and regulations affecting our industry

Dodd-Frank Wall Street Reform and Consumer Protection Act. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) was enacted into law. The Dodd-Frank Act established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to establish rules and regulations to implement the new legislation. Although the CFTC has issued final regulations to implement significant aspects of the legislation, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished. Additionally, certain aspects of the Dodd-Frank Act were repealed by the U.S. Congress in 2017.

In November 2013 and December 2016, the CFTC proposed rules establishing position limits with respect to certain futures and option contracts and equivalent swaps, subject to exceptions for certain bona fide hedging. As these new position limit rules are not yet final, the impact of these provisions on us is uncertain at this time.

Pursuant to the Dodd-Frank Act, absent an exception, mandatory clearing is now required for all market participants. 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 physical commodity swaps, and the trade execution requirement does not apply to swaps not subject to a clearing mandate. 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. The ultimate effect of the proposed rules and any additional regulations on our business is uncertain.

In December 2015, the CFTC issued final rules establishing minimum margin requirements for uncleared swaps for swap dealers and major swap participants. The final rules do not impose margin requirements on commercial end users. Although we expect to qualify for the end-user exception from the 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 current or future 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.

In addition to the CFTC’s swap regulations, certain foreign jurisdictions may adopt or implement laws and regulations relating to transactions in derivatives, including margin and central clearing requirements, which in each case may affect our counterparties and the derivatives markets generally. Other rules may alter the business practices of some of our counterparties and in some cases may cause them to stop transacting in or making markets in derivatives. Moreover, federal banking regulators are reevaluating the authorization under which banking entities subject to their authority may engage in physical commodities transactions.

Although we cannot predict the ultimate outcome of these rulemakings, they could result in increased costs and cash collateral requirements for the types of derivative instruments we use or otherwise limit our ability to manage our financial and commercial risks related to fluctuations in commodity prices. Additional effects of the regulations, including increased regulatory reporting and recordkeeping costs, increased regulatory capital requirements for our counterparties, and market dislocations or disruptions could have an adverse effect on our ability to hedge risks associated with our business.

Energy Policy Act of 2005. The Energy Policy Act of 2005 (“EPAct 2005”) included a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and made significant changes to the statutory framework affecting the energy industry. For example, EPAct 2005 amended the NGA to add an anti-market manipulation provision making it unlawful for any entity to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. In January 2006 the FERC issued rules implementing the anti-market manipulation provision of EPAct 2005. These anti-market manipulation rules apply to natural gas pipelines and storage companies which provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements described further below. The EPAct 2005 also provides the FERC with the power to assess civil penalties of up to $1,000,000 per day per violation for violations of the NGA and NGPA and disgorgement of profits associated with any violation.

FERC Market Transparency and Reporting Rules. The FERC requires wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year to report, on May 1 of each year, aggregate volumes of natural 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. The FERC also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting. Failure to comply with these reporting requirements could subject us to enhanced civil penalty liability under the EPAct 2005.

FTC and CFTC Market Manipulation Rules. Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 ("EISA") and regulations by the FTC. Under the EISA, the FTC issued its Petroleum Market Manipulation Rule (the "Rule"), which became effective in November 2009. The Rule prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. Under the EISA, the FTC has authority to request a court to impose fines of up to $1,000,000 per day per violation. The CFTC has also adopted anti-market manipulation regulations prohibiting, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC may assess fines of up to the greater of $1,000,000 or triple the monetary gain for violations of these anti-market manipulation regulations. Knowing or willful violations of the Commodity Exchange Act is also a felony.

Additional proposals and proceedings potentially affecting the crude oil and natural gas industry are brought before the U.S. Congress, the FERC and the courts from time to time. We cannot predict the ultimate impact these or the above laws and regulations may have on our crude oil and natural gas operations. We do not believe we will be affected in a materially different way than our similarly situated competitors.

Environmental regulation

General. We are subject to stringent and complex federal, state, and local laws, rules and regulations governing environmental compliance, including the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits to conduct exploration, drilling and production operations;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with crude oil and natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas including areas containing endangered species of plants and animals;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and
- impose substantial liabilities for pollution resulting from drilling and production operations.

These laws, rules and regulations may also restrict the rate of crude oil and natural gas production below a rate otherwise possible. The regulatory burden on the crude oil and natural gas industry increases the cost of doing business and affects profitability. Additionally, the U.S. Congress and federal and state agencies frequently revise environmental laws, rules and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the crude oil and natural gas industry could have a significant impact on our operating costs.

In March 2017, President Donald Trump issued an Executive Order titled "Promoting Energy Independence and Economic Growth" (the "March 2017 Executive Order") which states it is in the national interest of the United States to promote clean and safe development of energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation. The March 2017 Executive Order requires, among other things, the executive department and agencies to review existing regulations that potentially burden the development or use of domestically produced energy resources (with particular attention to crude oil, natural gas, coal, and nuclear energy) and suspend, revise, or rescind those regulations that unduly burden the development of such resources beyond the degree necessary to protect the public interest or otherwise comply with the law. In response to the March 2017 Executive Order, certain energy and climate-related regulations proposed or enacted under previous presidential administrations have been, or are in the process of being, reviewed, suspended, revised, or rescinded, some of which are described further below. Numerous regulations impacting the crude oil and natural gas industry are not expected to be impacted by the March 2017 Executive Order and will continue to be in effect. Additionally, undoing previously existing environmental regulations will likely involve lengthy notice-and-comment rulemaking and the resulting decisions may then be subject to litigation by opposition groups. Thus, it could take several years before existing regulations are revised or rescinded. Although further regulation of our industry may stall at the federal level under the March 2017 Executive Order, certain states have pursued additional regulation of our operations and other states may do so as well.

Environmental laws, rules and regulations. Some of the existing environmental laws, rules and regulations we are subject to include: (i) regulations by the U.S. Environmental Protection Agency ("EPA") and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the federal Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that may require the removal of previously disposed hazardous substances (including hazardous substances disposed of or released by prior owners or operators), the cleanup of property contamination (including groundwater contamination), and remedial lease restoration activities to prevent future contamination from prior operations; (iii) federal Department of Transportation safety laws and comparable state and local requirements; (iv) the federal Clean Air Act and comparable state and local requirements, which establish pollution control requirements for air emissions from our operations; (v) the federal Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (vi) the Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws which impose restrictions and strict controls with respect to the discharge of pollutants, including crude oil and other substances generated by our operations, into waters of the United States or state waters; (vii) the federal Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of solid and hazardous wastes, and comparable state statutes; (viii) the federal Safe Drinking Water Act ("SDWA") and analogous state laws which impose requirements relating to our underground injection activities; (ix) the National Environmental Policy Act and comparable state statutes, which require government agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment; (x) the federal Endangered Species Act and comparable state statutes, which afford protections to certain plant and animal species; (xi) the federal Migratory Bird Treaty Act, which imposes certain restrictions for the protection of migratory birds; (xii) the federal Bald and Golden Eagle Protection Act, which imposes certain restrictions for the protection of bald and golden eagles; (xiii) the federal Emergency Planning and Community Right to Know Act and comparable state statutes, which require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations, and (xiv) state regulations and statutes governing the handling, treatment, storage and disposal of technologically enhanced naturally occurring radioactive material. Failure to comply with these laws, rules and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays in the permitting or performance of projects, the issuance of orders enjoining performance of some or all of our operations, and potential litigation.

Air emissions and climate change. Federal, state and local laws and regulations have been and may be enacted to address concerns about the effects the emission of carbon dioxide, methane and other identified “greenhouse gases” may have on the environment and climate worldwide, generally referred to as “climate change.” For example, in October 2015 the EPA revised 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. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 35% of the U.S. counties, including all of the counties in North Dakota and all of the counties except for Bryan County in Oklahoma, as either “attainment/unclassifiable” or “unclassifiable” and is expected to issue attainment or nonattainment designations for the remaining areas of the U.S. not addressed under the November 2017 rule in the first half of 2018. Additionally, 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. The EPA has also adopted regulations under existing provisions of the federal Clean Air Act establishing, among other things, Prevention of Significant Deterioration (“PSD”) pre-construction and Title V operating permit reviews for certain large stationary sources. Moreover, the EPA’s source determination rule specifies that oil and gas production facilities are considered to be “adjacent” (and therefore aggregated for air permitting purposes) if they are on the same site or on sites that share equipment and are within ¼ mile of each other. This rule increases the potential for individual well facilities to be viewed collectively by the EPA as a single, large stationary source and, therefore, subject to PSD and/or Title V. Regulations related to greenhouse gas emissions 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 greenhouse gas 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. New Source Performance Standard (“NSPS”) Subpart OOOO (“Quad O”) requires, among other things, the reduction of volatile organic compound (“VOC”) emissions from three subcategories of fractured and refractured oil and gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured oil and gas wells. All three subcategories of wells must route flowback emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the "other" fractured and refractured wells must use reduced emission completions or "green completions." The rule also established specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The rule is designed to limit emissions of VOCs, sulfur dioxide, and hazardous air pollutants from a variety of sources within natural gas processing plants, oil and natural gas production facilities, and natural gas transmission compressor stations. We have modified our operations and well equipment as needed to comply with these rules. Ongoing compliance with the rules is not expected to affect us in a way that materially differs from our similarly situated competitors.

In addition, in June 2016 the EPA finalized new regulations (NSPS Subpart OOOOa, commonly referred to as "Quad Oa") setting methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities in an effort to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025 even though there was consensus at the time that oil and gas producers' compliance with Quad O had already achieved reductions in methane emissions.

However, in June 2017, the EPA proposed to stay certain portions of the NSPS Quad Oa rules described above for a period of two years while the rules are reconsidered in response to President Trump's March 2017 Executive Order to reduce the burden of federal regulations that may hinder economic growth and energy development. The EPA has not yet published a final rule issuing the stay, and, as a result, the Quad Oa rules are currently in effect but future implementation of the Quad Oa rules is uncertain at this time. As part of its reconsideration, the EPA may issue revised rules, the timing and impact of which is uncertain.

Additional regulation with respect to methane emissions occurred in November 2016 when the U.S. Department of Interior's Bureau of Land Management ("BLM") published a final rule commonly referred to as the "BLM Venting and Flaring Rule." Similar to Quad Oa, the BLM Venting and Flaring Rule imposes requirements related to methane emissions from crude oil and natural gas sources. However, in response to President Trump's March 2017 Executive Order, in December 2017 the BLM announced it was temporarily suspending or delaying certain requirements contained in its Venting and Flaring Rule until January 2019. That suspension is now being challenged in court and future implementation and impact of the rule remains uncertain. While additional federal regulation with respect to methane emissions appears unlikely in the near future, states may nevertheless pursue rules or enforcement actions designed to reduce methane emissions. To the extent new methane emission regulations—whether it is the BLM Venting and Flaring Rule, a prospective EPA rule targeting methane emissions from existing sources, or a state agency—impose reporting obligations on, or limit emissions of greenhouse gases from, our equipment and operations they could require us to incur costs to reduce emissions associated with our operations, but the impact of these measures is not expected to be material and will not affect us in a materially different way from our similarly situated competitors.

At an international level, in December 2015 a global climate agreement was reached in Paris at the 21st Conference of Parties organized by the United Nations under the Framework Convention on Climate Change. The agreement, which goes into effect in 2020, resulted in nearly 200 countries, originally including the United States, committing to work towards limiting global warming and agreeing to a monitoring and review process of greenhouse gas emissions. The agreement includes binding and non-binding elements and did not require ratification by the U.S. Congress. In June 2017, President Trump announced the United States will withdraw from and cease implementation of the Paris climate agreement, but indicated the U.S. may re-engage in the agreement if more favorable terms can be re-negotiated. In August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris climate agreement. The exit process provided for under the Paris agreement could take up to four years. The United States' adherence to the exit process is uncertain and the terms on which the United States may reenter the Paris agreement or a separately negotiated agreement are unclear. Although the U.S. has ceased its participation in the Paris agreement, the agreement nonetheless may result in increased political pressure on the United States to ensure continued compliance with enforcement measures under the Clean Air Act and may spur further initiatives aimed at reducing greenhouse gas emissions in the future.

While the U.S. Congress has from time to time considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of enacted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal legislation, a number of state and regional efforts have emerged aimed at tracking and reducing greenhouse gas emissions by means of cap and trade programs that typically require major sources of greenhouse gas emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those greenhouse gases. There has also been discussion of imposing a federal carbon tax on all fossil fuel production, though such a tax appears unlikely at this time. Although it is not possible to predict how such legislation or new regulations adopted to address greenhouse gas emissions will impact our business, any future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. In addition, substantial limitations on greenhouse gas emissions could adversely affect the demand for the

crude oil and natural gas we produce and lower the value of our reserves. Finally, some scientists have concluded increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes having significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects from such causes were to occur, they could have an adverse effect on our exploration and production operations.
Both the EPA and the state of North Dakota pursued enforcement actions in 2016 against operators related to emissions generally and alleged noncompliance with the requirements of Quad O, Quad Oa, and relevant state regulations more specifically. One such enforcement action by the EPA against an operator resulted in a consent decree between the parties

requiring the operator to incur costs associated with a civil penalty, emissions-related mitigation projects, and implementation of a robust leak detection and repair program applicable to all of the operator's wells in North Dakota. Finally, the U.S. Department of Justice ("DOJ") announced in 2016 it had partnered with the Occupational Safety and Health Administration to pursue a "Worker Endangerment Initiative" seeking to promote worker safety by pursuing not only worker safety claims in connection with worker safety incidents but also environmental claims.

Environmental protection and natural gas flaring. We strive to operate in accordance with all applicable regulatory and legal requirements and have focused on continuously improving our environmental performance; however, at times circumstances may arise that adversely affect our compliance with applicable environmental requirements. We have established internal policies, procedures and processes regarding environmental matters for all employees, contractors, and vendors. In connection with our environmental initiatives, we work to identify and manage our environmental risks and the impact of our operations and continually improve our environmental compliance. However, we cannot guarantee our efforts will always be successful.

One of our environmental initiatives is the reduction of air emissions produced from our operations, particularly with respect to the flaring of natural gas from our operated well sites in the Bakken field of North Dakota. North Dakota statutes permit flaring of natural gas from a well that has not been connected to a gas gathering line for a period of one year from the date of a well's first production. After one year, a producer is required to cap the well, connect it to a gas gathering line, find acceptable alternative uses for a percentage of the flared gas, or apply to the NDIC for a written exemption for any future flaring; otherwise, the producer is required to pay royalties and production taxes based on the volume and value of the gas flared from the unconnected well. While the NDIC ultimately determines the volume and value of any such gas flared and the applicable royalties and production taxes, the NDIC has thus far generally accepted our methods for calculating these amounts. Furthermore, the NDIC has generally accepted applications we have submitted to secure exemptions from the post-year flaring restrictions. Finally, NDIC rules for new drilling permit applications also require the submission of gas capture plans addressing measures taken by operators to capture and not flare produced gas, regardless of whether it has been or will be connected within the first year of production. Thus far, the NDIC has generally accepted our gas capture plans submitted with applications for drilling permits. The deadline to comply with the requirement to capture 85% of the natural gas produced from a field was November 1, 2016, and the target capture percentage increases to 88% beginning November 1, 2018 and 91% beginning November 1, 2020. Ongoing compliance with the NDIC's flaring requirements or the imposition of any additional limitations on flaring could result in increased costs and have an adverse effect on our operations.

For the year ended December 31, 2017, we delivered approximately 90% of our operated natural gas production in the North Dakota Bakken field to market, flaring approximately 10% compared to 9% in 2016 and 13% in 2015. According to data published by the NDIC, our industry as a whole flared approximately 12% of produced natural gas volumes in the North Dakota Bakken field during 2017. We are a participant in the NDIC's Flaring Reduction Task Force and are engaged in working with other task force members and the NDIC to develop action plans for mitigating natural gas flaring in the state. Flared natural gas volumes from our operated SCOOP and STACK properties in Oklahoma are negligible given the existence of established natural gas transportation infrastructure.

There are environmental and financial risks associated with natural gas flaring, and we attempt to manage these risks on an ongoing basis. We have taken numerous actions to reduce flaring from our operated well sites, such as coordinating our well completion operations to coincide with well connections to gathering systems in order to minimize flaring; however, we may not always be successful in these efforts. Our ultimate goal is to reduce natural gas flaring from our operated well sites as much as practicable. For example, in operating areas such as the Buffalo Red River units in South Dakota, the quality of the natural gas is not adequate to meet requirements for sale, so we employ processes to efficiently combust the gas in an effort to minimize impacts to the environment. Our levels of flaring are and will be dependent upon external factors such as investment from third parties in the development of gas gathering systems, state regulations, and the granting of reasonable right-of-way access by land owners. For example, over the past year insufficient takeaway capacity in North Dakota has created challenges for all operators and contributed to an increase in volumes of flared gas. Increased emissions from a multi-well pad facility or centralized production facilities due to flaring could require us to adhere to PSD or Title V permit requirements. We have filed several permits to construct major sources (i.e., facilities from which emissions of a criteria pollutant (e.g., carbon monoxide or volatile organic compounds) are expected to exceed 100 tons per year) relating to facilities where takeaway capacity is currently constrained and creating a potential to emit in excess of 100 tons per year.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures are included within our overall capital and operating budgets and are not separately itemized. Although we believe our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you the passage of more stringent laws or regulations in the future will not materially impact our financial position, results of operations or cash flows.

Hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppant and additives under pressure into rock formations to stimulate crude oil and natural gas production. In recent years there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies and to induce seismic events. As a result, several federal and state agencies are studying the environmental risks with respect to hydraulic fracturing, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 related to such activities. In May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. In June 2016, the EPA finalized a regulation under the Clean Water Act prohibiting discharges to publicly owned treatment works of wastewater from onshore unconventional oil and gas extraction facilities. It has not been our practice to discharge wastewater to publicly owned treatment works, so the impact of this new regulation on us is not expected to be material.

In December 2016 the EPA published a final study of the potential impacts of hydraulic fracturing activities on water resources. In its report, the EPA indicated it found evidence hydraulic fracturing activities can impact drinking water resources under some circumstances. The report identified certain conditions where impacts from hydraulic fracturing activities can potentially be more frequent or severe. These include water withdrawals for hydraulic fracturing in times or areas of low water availability; spills during the handling of hydraulic fracturing fluids, chemicals or produced water resulting in large volumes or high concentrations of chemicals reaching groundwater resources; injection of hydraulic fracturing fluids into wells with inadequate mechanical integrity thereby allowing gases or liquids to move to groundwater resources; injection of hydraulic fracturing fluids directly into groundwater resources; discharge of inadequately treated hydraulic fracturing wastewater to surface water; and disposal or storage of hydraulic fracturing wastewater in unlined pits thereby resulting in contamination of groundwater resources. In its final report, the EPA indicated it was not able to calculate or estimate the national frequency of impacts on drinking water resources from hydraulic fracturing activities or fully characterize the severity of impacts. Nonetheless, the results of the EPA's study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

In March 2015, the BLM issued final rules related to the regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. Several parties challenged the regulations and the U.S. District Court of Wyoming temporarily stayed implementation of the regulations. In June 2016, the U.S. District Court of Wyoming ruled the BLM lacked the statutory authority to promulgate the regulations. The U.S. Department of Interior appealed the decision. In December 2017, the BLM formally rescinded its March 2015 hydraulic fracturing rules, citing unjustified administrative burdens and compliance costs arising from a reassessment performed in response to President Trump's March 2017 Executive Order to reduce the burden of federal regulations that may hinder economic growth and energy development. In January 2018, litigation challenging the BLM's rescission of the March 2015 final rules was brought in federal court. As of December 31, 2017, we held approximately 65,500 net undeveloped acres on federal land, representing approximately 11% of our total net undeveloped acres.

At the state level, several states in which we operate have adopted or are considering adopting legal requirements imposing more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating or prohibiting the time, place and manner of drilling activities or hydraulic fracturing activities. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. Regulators in states in which we operate are considering additional requirements related to seismicity and its potential association with hydraulic fracturing. For example, the Oklahoma Corporation Commission (the "OCC") has promulgated guidance for operators of crude oil and gas wells in certain seismically-active areas of the SCOOP and STACK plays in Oklahoma. The OCC's guidance provides for seismic monitoring and for implementation of mitigation procedures, which may include a suspension of operations in the event of concurrent seismic events within a particular radius of operations of a magnitude exceeding 2.5 on the Richter scale. The OCC may update this guidance to impose a larger monitoring area and more stringent requirements for notification and suspension of operations. If seismic events exceeding the OCC guidance thresholds were to occur near our active stimulation operations on a frequent basis, they could have an adverse effect on our operations.

We voluntarily participate in FracFocus, a national publicly accessible Internet-based registry developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. This registry, located at www.fracfocus.org, provides our industry with an avenue to voluntarily disclose additives used in the hydraulic fracturing process. The additives used in the hydraulic fracturing process on all wells we operate are disclosed on that website.

The adoption of any future federal, state or local laws, rules or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, hydraulic fracturing processes in areas in which we operate could make it more difficult and expensive to complete crude oil and natural gas wells in low-permeability formations, increase our costs of compliance and doing business, and delay, prevent or prohibit the development of natural resources from unconventional formations. Compliance, or the consequences of our failure to comply, could have a material adverse effect on our financial condition and results of operations. At this time it is not possible to estimate the potential impact on our business if such federal or state legislation is enacted into law.

Waste water disposal. Underground injection wells are a predominant method for disposing of waste water from oil and gas activities. In response to seismic events near underground injection wells used for the disposal of oil and gas-related waste waters, federal and some state agencies are investigating whether such wells have caused increased seismic activity. Some states, including states in which we operate, have delayed permit approvals, mandated a reduction in injection volumes, or have shut down or imposed moratoria on the use of injection wells. Regulators in states in which we operate are considering additional requirements related to seismicity. For example, the OCC has adopted rules for operators of saltwater disposal wells in certain seismically-active areas in the Arbuckle formation of Oklahoma. These rules require, among other things, that disposal well operators conduct mechanical integrity testing or make certain demonstrations of such wells' respective depths that, depending on the depth, could require plugging the well and/or the reduction of volumes disposed in such wells. Oklahoma has adopted a "traffic light" system wherein the 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. At the federal level, the EPA's current regulatory requirements for such wells do not require the consideration of seismic impacts when issuing permits. We cannot predict the EPA's future actions in this regard. The introduction of new environmental initiatives and regulations related to the disposal of wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize underground injection wells. A lack of waste water disposal sites could cause us to delay, curtail or discontinue our exploration and development plans. Additionally, increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. These costs are commonly incurred by all oil and gas producers and we do not believe the costs associated with the disposal of produced water will have a material adverse effect on our operations to any greater degree than other similarly situated competitors. In recent years we have increased our operation and use of water recycling and distribution facilities in Oklahoma that economically reuse stimulation water for both operational efficiencies and environmental benefits.

Employee Health and Safety. We are also subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulation under Title III of the federal superfund Amendment and Reauthorization Act and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local governmental authorities and citizens.

Employees

As of December 31, 2017, we employed 1,127 people. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

Company Contact Information

Our corporate internet website is www.clr.com. Through the investor relations section of our website, we make available free of charge our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after the report is filed with or furnished to the SEC. For a current version of various corporate governance documents, including our Code of

Business Conduct and Ethics, Corporate Governance Guidelines, and the charters for various committees of our Board of Directors, please see our website. We intend to disclose amendments to, or waivers from, our Code of Business Conduct and Ethics by posting to our website. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

We intend to use our website as a means of disclosing material information and for complying with our disclosure obligations under SEC Regulation FD. Such disclosures will be included on our website in the “For Investors” section. Accordingly, investors should monitor that portion of our website in addition to following our press releases, SEC filings and public conference calls and webcasts.

We file periodic reports and proxy statements with the SEC. 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, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC's website is www.sec.gov.

Our principal executive offices are located at 20 N. Broadway, Oklahoma City, Oklahoma 73102, and our telephone number at that address is (405) 234-9000.

Item 1A. Risk Factors

You should carefully consider each of the risks described below, together with all other information contained in this report in connection with an investment in our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of our securities could decline and you may lose all or part of your investment.

Substantial declines in commodity prices or extended periods of low commodity prices adversely affect our business, financial condition, results of operations and cash flows and our ability to meet our capital expenditure needs and financial commitments.

The prices we receive for sales of our crude oil and natural gas production impact our revenue, profitability, access to capital, capital budget and rate of growth. Crude oil and natural gas are commodities and prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for crude oil and natural gas have been volatile and unpredictable. For example, during 2017 the NYMEX West Texas Intermediate ("WTI") crude oil and Henry Hub natural gas spot prices ranged from approximately $42 to $60 per barrel and $2.45 to $3.70 per MMBtu, respectively. Commodity prices may remain volatile and unpredictable in 2018 and beyond.

We have hedged the majority of our forecasted 2018 natural gas production. Our future crude oil production is currently unhedged and directly exposed to continued volatility in market prices, whether favorable or unfavorable.

The prices we receive for sales of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide, domestic and regional economic conditions impacting the supply of, and demand for, crude oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries and other producing nations;
- the level of national and global crude oil and natural gas exploration and production activities;
- the level of national and global crude oil and natural gas inventories, which may be impacted by economic sanctions applied to certain producing nations;
- the level and effect of trading in commodity futures markets;
- the relative strength of the United States dollar compared to foreign currencies;
- the price and quantity of imports of foreign crude oil;
- the price and quantity of exports of crude oil or liquefied natural gas from the United States;
- military and political conditions in, or affecting other, crude oil-producing and natural gas-producing countries;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulations;
- localized supply and demand fundamentals;
- the cost and availability, proximity and capacity of transportation, processing, storage and refining facilities for various quantities and grades of crude oil and natural gas;
- adverse weather conditions and natural disasters;
- technological advances affecting energy consumption;
- the effect of worldwide energy conservation and environmental protection efforts; and
- the price and availability of alternative fuels or other energy sources.

Sustained material declines in commodity prices reduce our cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; may limit our ability to borrow money or raise additional capital; and may reduce our proved reserves and the amount of crude oil and natural gas we can economically produce.

In addition to reducing our revenue, cash flows and earnings, depressed prices for crude oil and/or natural gas may adversely affect us in a variety of other ways. If commodity prices decrease substantially, some of our exploration and development projects could become uneconomic, and we may also have to make significant downward adjustments to our estimated proved reserves and our estimates of the present value of those reserves. If these price effects occur, or if our estimates of production or economic factors change, accounting rules may require us to write down the carrying value of our crude oil and/or natural gas properties. Lower commodity prices may also reduce our access to capital and lead to a downgrade or other negative rating

action with respect to our credit rating. A downgrade of our credit rating could negatively impact our cost of capital, increase the borrowing costs under our revolving credit facility, and limit our ability to access capital markets and execute aspects of our business plans. As a result, substantial declines in commodity prices or extended periods of low commodity prices may materially and adversely affect our future business, financial condition, results of operations, cash flows, liquidity and ability to finance planned capital expenditures and commitments.

A substantial portion of our producing properties is located in limited geographic areas, making us vulnerable to risks associated with having geographically concentrated operations.

A substantial portion of our producing properties is located in the Bakken field of North Dakota and Montana, with that area comprising approximately 55% of our crude oil and natural gas production and approximately 64% of our crude oil and natural gas revenues for the year ended December 31, 2017. Approximately 48% of our estimated proved reserves were located in the Bakken as of December 31, 2017. Additionally, in recent years we have significantly expanded our operations in Oklahoma with our increased activity in the SCOOP and STACK plays. Our properties in Oklahoma comprised approximately 41% of our crude oil and natural gas production and approximately 31% of our crude oil and natural gas revenues for the year ended December 31, 2017. Approximately 50% of our estimated proved reserves were located in Oklahoma as of December 31, 2017.

Because of this concentration in limited geographic areas, the success and profitability of our operations may be disproportionately exposed to regional factors compared to competitors having more geographically dispersed operations. These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the regions and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints; (ii) the availability of rigs, equipment, oilfield services, supplies, and labor; (iii) the availability of processing and refining facilities; and (iv) infrastructure capacity. In addition, our operations in the Bakken field and Oklahoma may be adversely affected by severe weather events such as floods, blizzards, ice storms and tornadoes, which can intensify competition for the items and services described above and may result in periodic shortages. The concentration of our operations in limited geographic areas also increases our exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife, and unexpected events that may occur in the regions such as natural disasters, seismic events (which may result in third-party lawsuits), industrial accidents, labor difficulties, civil disturbances, public protests, or terrorist attacks. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition, results of operations and cash flows.

Volatility in the financial markets or in global economic factors could adversely impact our access to capital and business and financial condition.

United States and global economies may experience periods of turmoil and volatility from time to time, resulting in diminished liquidity and credit availability, inability to access capital markets, high unemployment, unstable consumer confidence, and diminished consumer demand and spending. In recent years, certain global economies have experienced periods of political uncertainty, slowing economic growth, rising interest rates, changing economic sanctions, and currency volatility. These global macroeconomic conditions may put downward pressure on commodity prices and have a negative impact on our revenues, profitability, operating cash flows, liquidity and financial condition.

Historically, we have used cash flows from operations, borrowings under our revolving credit facility and proceeds from capital market transactions and asset dispositions to fund capital expenditures. Volatility in U.S. and global financial and equity markets, including market disruptions, limited liquidity, and interest rate volatility, may negatively impact our ability to obtain needed capital on acceptable terms or at all and may increase our cost of financing.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on acceptable terms, which could lead to a decline in our crude oil and natural gas reserves, production and revenues. In addition, funding our capital expenditures with additional debt will increase our leverage and doing so with equity securities may result in dilution that reduces the value of your stock.

The crude oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development, exploitation, production and acquisition of crude oil and natural gas reserves. We have budgeted $2.30 billion for capital expenditures in 2018 (excluding acquisitions which are not budgeted) of which $1.99 billion is allocated for exploration and development drilling. We may adjust our 2018 capital spending plans upward or downward depending on market conditions.

Historically, our capital expenditures have been financed with cash generated by operations, borrowings under our revolving credit facility and proceeds from the issuance of debt and equity securities. Additionally, in recent years non-strategic asset dispositions have provided a source of cash flow for use in reducing outstanding debt arising from our capital program. The actual amount and timing of future capital expenditures may differ materially from our estimates as a result of, among others, changes in commodity prices, available cash flows, lack of access to capital, unbudgeted acquisitions, actual drilling and completion results, the availability of drilling and completion rigs and other services and equipment, the availability of transportation and processing capacity, and regulatory, technological and competitive developments.

Our cash flows from operations and access to capital are subject to a number of variables, including but not limited to:

- the volume and value of our proved reserves;
- the volume of crude oil and natural gas we are able to produce and sell from existing wells;
- the prices at which crude oil and natural gas are sold;
- our ability to acquire, locate and produce new reserves;
- our ability to dispose of assets or enter into joint development arrangements on satisfactory terms; and
- the ability and willingness of our lenders to extend credit or of participants in the capital markets to invest in our senior notes or equity securities.

If oil and gas industry conditions weaken as a result of low commodity prices or other factors, our ability to borrow may decrease and we may have limited ability to obtain the capital necessary to sustain our operations at planned levels. Currently, we have a revolving credit facility with lender commitments totaling $2.75 billion that matures in May 2019. In the future, we may not be able to access adequate funding under our revolving credit facility if our lenders are unwilling or unable to meet their funding obligations or increase their commitments under the credit facility. Our lenders could decline to increase their commitments based on our financial condition, the financial condition of our industry or the economy as a whole or for other reasons beyond our control. Due to these and other factors, we cannot be certain that funding, if needed, will be available to the extent required or on terms we find acceptable. If operating cash flows are insufficient and we are unable to access funding or execute capital transactions when needed on acceptable terms, we may not be able to fully implement our business plans, fund our capital program and commitments, complete new property acquisitions to replace reserves, take advantage of business opportunities, respond to competitive pressures, or refinance debt obligations as they come due. Should any of the above risks occur, they could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We intend to finance future capital expenditures primarily through cash flows from operations, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility or proceeds from asset sales or joint development arrangements. However, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. If we issue additional debt a portion of our cash flows from operations will need to be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital needs, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Drilling for and producing crude oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploration, development and production activities. Our crude oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable crude oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating wells may be uncertain before drilling commences.

Risks we face while drilling include, but are not limited to, failing to place our well bore in the desired target producing zone; not staying in the desired drilling zone while drilling horizontally through the formation; failing to run our casing the entire length of the well bore; and not being able to run tools and other equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages; failing to run tools the entire length of the well bore during completion operations; not successfully cleaning out the well bore after completion of the final fracture stimulation stage; increased seismicity in areas near our completion activities; unintended interference of completion activities performed by us or by third parties with nearby operated or non-operated wells being drilled, completed, or producing; and failure of our optimized completion techniques to yield expected levels of production.

Further, many factors may curtail, delay or cancel scheduled drilling projects, including but not limited to:

- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment or qualified personnel;
- shortages of or delays in obtaining components used in fracture stimulation processes such as water and proppants;
- delays associated with suspending our operations to accommodate nearby drilling or completion operations being conducted by other operators;
- mechanical difficulties, fires, explosions, equipment failures or accidents, including ruptures of pipelines or train derailments;
- restrictions on the use of underground injection wells for disposing of waste water from oil and gas activities;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- decreases in, or extended periods of low, crude oil and natural gas prices;
- limited availability of financing with acceptable terms;
- title problems;
- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by us or by third party service providers;
- limitations in infrastructure, including transportation, processing and refining capacity, or markets for crude oil and natural gas; and
- delays imposed by or resulting from compliance with regulatory requirements including permitting.

Any of the above events could hinder our ability to conduct normal operations and could adversely affect our business, financial condition, results of operations and cash flows.

Reserve estimates depend on many assumptions that will likely turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The Company’s current estimates of reserves could change, potentially in material amounts, in the future, in particular due to changes in commodity prices.

The process of estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of available technical data and many assumptions, including assumptions relating to current and future economic conditions, production rates, drilling and operating expenses, and commodity prices. Any significant inaccuracy in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves for information about our estimated crude oil and natural gas reserves, standardized measure of discounted future net cash flows, and PV-10 as of December 31, 2017.

In order to prepare reserve estimates, we must project production rates and the amount and timing of development expenditures. Our booked proved undeveloped reserves must be developed within five years from the date of initial booking under SEC reserve rules. Changes in the timing of development plans that impact our ability to develop such reserves in the required time frame have resulted, and will likely in the future result, in fluctuations in reserves between periods as reserves booked in one period may need to be removed in a subsequent period. In 2017, 89 MMBoe of proved undeveloped reserves were removed from our year-end reserve estimates associated with drilling locations no longer scheduled to be developed within five years from the date of initial booking.

We must also analyze available geological, geophysical, production and engineering data in preparing reserve estimates. The extent, quality and reliability of this data can vary which in turn can affect our ability to model the porosity, permeability and pressure relationships in unconventional resources. The process also requires economic assumptions, based on historical data but projected into the future, about matters such as crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

The prices used in calculating our estimated proved reserves are calculated by determining the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding 12 months. For the year ended December 31, 2017, average prices used to calculate our estimated proved reserves were $51.34 per Bbl for crude oil and $2.98 per MMBtu for natural gas ($47.03 per Bbl for crude oil and $3.00 per Mcf for natural gas adjusted for location and quality differentials). Actual future prices may be materially higher or lower than those used in our year-end estimates.

NYMEX WTI crude oil and Henry Hub

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natural gas first-day-of-the-month commodity prices for January 1, 2018 and February 1, 2018 averaged $63.11 per barrel and $3.40 per MMBtu, respectively. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve, Standardized Measure, and PV-10 Sensitivities for proved reserve sensitivities under certain increasing and decreasing commodity price scenarios.
Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves will vary and could vary significantly from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves, which in turn could have an adverse effect on the value of our assets. In addition, we may adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development activities, prevailing crude oil and natural gas prices and other factors, many of which are beyond our control.
The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated crude oil and natural gas reserves.
You should not assume the present value of future net revenues from our proved reserves is the current market value of our estimated crude oil and natural gas reserves. We base the estimated discounted future net revenues from proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. Actual future prices may be materially higher or lower than the average prices used in the calculations. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve, Standardized Measure, and PV-10 Sensitivities for Standardized Measure and PV-10 sensitivities under certain increasing and decreasing commodity price scenarios.
Actual future net revenues from crude oil and natural gas properties will be affected by factors such as:
- the actual prices we receive for sales of crude oil and natural gas;
- the actual cost and timing of development and production expenditures;
- the timing and amount of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of costs in connection with the development and production of crude oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the use of a 10% discount factor, which is required by the SEC to be used to calculate discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the crude oil and natural gas industry in general. Any significant variances in timing or assumptions could materially affect the estimated present value of our reserves, which in turn could have an adverse effect on the value of our assets.
We may be required to further write down the carrying values of our crude oil and natural gas properties if commodity prices decline or our development plans change.
Accounting rules require we periodically review the carrying values of our crude oil and natural gas properties for possible impairment. Proved properties are reviewed for impairment on a field-by-field basis each quarter. We use the successful efforts method of accounting whereby the estimated future cash flows expected in connection with a field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value using a discounted cash flow model.
Based on specific market factors, prices, and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying values of our crude oil and natural gas properties. A write-down results in a non-cash charge to earnings. We have incurred impairment charges in the past and may incur additional impairment charges in the future, particularly if commodity prices decline, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our crude oil and natural gas reserves, our reserves and production will decline, which could adversely affect our cash flows and results of operations.

Unless we conduct successful exploration, development and exploitation activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing crude oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil and natural gas reserves and production, and therefore our cash flows and results of operations, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations could be materially adversely affected.

The unavailability or high cost of drilling rigs, well completion crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within budget and on a timely basis.

In the regions in which we operate, there have historically been shortages of drilling rigs, well completion crews, equipment, supplies, personnel or oilfield services, including key components used in fracture stimulation processes such as water and proppants, as well as high costs associated with these critical components of our operations. The demand for qualified and experienced oilfield service providers and associated equipment, supplies, and materials can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages.

Certain drilling and completion costs and costs of oilfield services, equipment, and materials decreased in recent years as service providers reduced their costs in response to reduced demand arising from low crude oil prices. However, inflationary pressures returned in 2017 and are expected to continue in 2018 in conjunction with the stabilization and improvement in crude oil prices in recent months.

As a result of the low commodity price environment in recent years, the number of providers of services, equipment, and materials decreased in the regions where we operate. Further, increased industry drilling and completion activities in recent months prompted by improvement in crude oil prices may cause shortages or higher costs of services, equipment, and materials. Such shortages or higher costs could delay the execution of our drilling and development plans, including our plans to work down our large inventory of uncompleted wells, or cause us to incur expenditures not provided for in our capital budget or to not achieve the rates of return we are targeting for our development program, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We may incur substantial losses and be subject to substantial liability claims as a result of our crude oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and under-insured events could materially and adversely affect our business, financial condition or results of operations. Our crude oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires and explosions;
- ruptures of pipelines or storage facilities;
- loss of product or property damage occurring as a result of transfer to a rail car or train derailments;
- personal injuries and death;
- adverse weather conditions and natural disasters; and
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by us or by third party service providers.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to or destruction of property, natural resources and equipment;

- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations;
- repair and remediation costs; and
- litigation.

We may elect to not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented or for other reasons. In addition, pollution and environmental risks are generally not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Prospects we decide to drill may not yield crude oil or natural gas in economically producible quantities.

Prospects we decide to drill that do not yield crude oil or natural gas in economically producible quantities may adversely affect our results of operations and financial condition. In this report, we describe some of our current prospects and plans to explore and develop those prospects. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect requiring substantial additional seismic data processing and interpretation. It is not possible to predict with certainty whether any particular prospect will yield crude oil or natural gas in sufficient quantities to recover drilling or completion costs or be economically producible. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether crude oil or natural gas will be present or, if present, whether crude oil or natural gas will be present in economically producible quantities. We cannot assure you the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

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. Our ability to drill and develop these locations is subject to a number of uncertainties, including crude oil and natural gas prices; the availability of capital, drilling rigs, well completion crews, and transportation and processing capacity; costs; drilling results; regulatory approvals; and other factors. If future drilling results 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 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 sufficient quantities to achieve an economic return. 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. Low commodity prices, reduced capital spending, lack of available drilling and completion rigs and crews, 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 57% of our total net undeveloped acreage at December 31, 2017. At that date, we had leases representing 102,258 net acres expiring in 2018, 145,997 net acres expiring in 2019, and 93,664 net acres expiring in 2020. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Our proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2017, approximately 55% 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 may not prove to be accurate. Our reserve report at December 31, 2017 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $6.4 billion. We cannot be certain the estimated costs of the development of these reserves are accurate, development will occur as scheduled, or 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 as a result of our inability to fund necessary capital expenditures or otherwise, 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 not developed within this five-year time frame. Such removals have occurred in the past and will likely occur in the future. A removal of such reserves could adversely affect our operations. In 2017, 89 MMBoe of proved undeveloped reserves were removed from our year-end reserve estimates associated with drilling locations no longer scheduled to be developed within five years from the date of initial booking.

Our business depends on crude oil and natural gas transportation, processing, and refining facilities, most of which are owned by third parties.

The value we receive for our crude oil and natural gas production depends in part on the availability, proximity and capacity of gathering, pipeline and rail systems and processing and refining facilities owned by third parties. The inadequacy or unavailability of capacity on these systems and facilities could result in the shut-in of producing wells, the delay or discontinuance of development plans for properties, or higher operational costs associated with air quality compliance controls. Although we have some contractual control over the transportation of our products, changes in these business relationships or failure to obtain such services on acceptable terms could adversely affect our operations. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made for the sale or delivery of our products and acreage lease terminations could result if production is shut-in for a prolonged period.

The disruption of transportation, processing or refining facilities due to labor disputes, maintenance, civil disturbances, public protests, terrorist attacks, cyber attacks, adverse weather, natural disasters, seismic events, changes in tax and energy policies, federal, state and international regulatory developments, changes in supply and demand, equipment failures or accidents, including pipeline and gathering system ruptures or train derailments, and general economic conditions could negatively impact our ability to achieve the most favorable prices for our crude oil and natural gas production. We have no control over when or if access to such facilities would be restored or the impact on prices in the areas we operate. A significant shut-in of production in connection with any of the aforementioned items could materially affect our cash flows, and if a substantial portion of the impacted production fulfills transportation commitments or is hedged at lower than market prices, those commitments or financial hedges would have to be paid from borrowings absent sufficient cash flows.

Our operated crude oil and natural gas production is transported to market centers primarily using pipeline and rail transportation facilities owned and operated by third parties. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry for a discussion of regulations impacting the transportation of crude oil and natural gas. We do not currently own or operate transportation infrastructure; however, compliance with regulations that impact the transportation of crude oil or natural gas could increase our costs of doing business and limit our ability to transport and sell our production at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

Our business depends on the availability of water and the ability to dispose of waste water from oil and gas activities. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

With current technology, water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection wells.

In addition, concerns have been raised about the potential for seismic events to occur from the use of underground injection wells, a predominant method for disposing of waste water from oil and gas activities. Rules and regulations have been developed in Oklahoma to address these concerns by limiting or eliminating the ability to use disposal wells in certain locations or increasing the cost of disposal. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations. Some states, including states in which we operate, have delayed permit approvals, mandated a reduction in injection volumes, or have shut down or imposed moratoria on the use of injection wells. Regulators in some states, including states in which we operate, are considering additional requirements related to seismicity. For example, in Oklahoma, the Oklahoma Corporation Commission ("OCC") has adopted rules for operators of saltwater disposal wells in certain seismically-active areas in the Arbuckle formation of the state. These rules require disposal well operators, among other things, to conduct mechanical integrity testing or make certain demonstrations of such wells' respective depths that, depending on the depth, could require plugging the well and/or the reduction of volumes disposed in such wells. Oklahoma has adopted a "traffic light" system wherein the 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.

Compliance with existing or new environmental regulations and permit requirements governing the withdrawal, storage, and use of water necessary for hydraulic fracturing of wells or the disposal of waste water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our crude oil and natural gas exploration and production operations are subject to complex and stringent federal, state and local laws and regulations, including those governing environmental protection, the occupational health and safety aspects of our operations, the discharge of materials into the environment, and the protection of certain plant and animal species. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry for a description of the laws and regulations that affect us. In order to conduct operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Environmental regulations may restrict the types, quantities and concentration of materials released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenues.

Failure to comply with laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including investigatory actions, the assessment of monetary penalties, the imposition of remedial requirements, the issuance of orders or judgments limiting or enjoining future operations and litigation. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. For instance, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Moreover, our costs of compliance with existing laws could be substantial and may increase, or unforeseen liabilities could be imposed, if existing laws and regulations are revised or reinterpreted or if new laws and regulations become applicable to our operations. If we are not able to recover the increased costs through insurance or increased revenues, our business, financial condition, results of operations and cash flows could be adversely affected.

Climate change legislation or regulations governing the emissions of “greenhouse gases” could result in increased operating costs, limitations in our ability to develop and produce reserves, and reduced demand for the crude oil, natural gas and natural gas liquids we produce.

In response to EPA findings that emissions of carbon dioxide, methane and other greenhouse gases endanger human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act establishing, among other things, 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 greenhouse gas emissions are also required to meet “best available control technology” standards established on a case-by-case basis. For further discussion of Title V and PSD concerns, see Part I, Item 1. Business–Regulation of the Crude Oil and Natural Gas Industry–Environmental regulation–Air emissions and climate change. Also see Part I, Item 1. Business–Regulation of the Crude Oil and Natural Gas Industry–Environmental regulation–Environmental protection and natural gas flaring. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas 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. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry—Environmental regulation—Air emissions and climate change for further discussion of the laws and regulations that affect us with respect to climate change initiatives. Regulations related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. Certain previously existing climate-related regulations, such as those related to the control of methane emissions, have been, or are in the process of being, reviewed, suspended, revised, or rescinded in response to President Trump's March 2017 Executive Order. Undoing previously existing regulations will likely involve lengthy notice-and-comment rulemaking and the resulting decisions may then be subject to litigation by opposition groups. Thus, it could take several years before existing regulations are revised or rescinded. Although further climate-related regulation of our industry may stall at the federal level under the March 2017 Executive Order, certain states have pursued additional regulation of our operations related to the emission of greenhouse gases and other states may do so as well. For instance, several state and regional greenhouse gas cap and trade programs have emerged, while other states have imposed limitations on emissions of methane through equipment control and leak detection and repair requirements.

The implementation of, and compliance with, regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions, install new equipment to reduce emissions of greenhouse gases associated with our operations, or limit our ability to develop and produce our reserves. In addition, substantial limitations on greenhouse gas emissions could adversely affect the demand for the crude oil and natural gas we produce, which could lower the value of our reserves and have a material adverse effect on our business, financial condition, results of operations and cash flows.

Finally, some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods or other climatic events. If any such effects were to occur as a result of climate change or otherwise, they could have an adverse effect on our assets and operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays, and an inability to develop existing reserves or to book future reserves.

Hydraulic fracturing is an important and commonly used process in the completion of crude oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the high-pressure injection of water, sand or other proppant and additives into rock formations to stimulate crude oil and natural gas production. In recent years there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies and to induce seismic events. As a result, several federal and state regulatory initiatives have emerged that seek to increase the regulatory burden imposed on hydraulic fracturing. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry—Environmental regulation—Hydraulic fracturing for a description of the laws and regulations that affect us with respect to hydraulic fracturing.

States in which we operate have adopted or are considering adopting legal requirements imposing more stringent permitting, disclosure, and well construction and reclamation requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating or prohibiting the time, place and manner of drilling activities or hydraulic fracturing activities. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards.

The adoption of any future federal, state or local law or implementing regulation imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process, or the discovery of groundwater contamination or other adverse environmental effects directly connected to hydraulic fracturing, could make it more difficult and more expensive to complete crude oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay, prevent or prohibit the development of natural resources from unconventional formations. In the event regulations are adopted to prohibit or significantly limit the use of hydraulic fracturing in states in which we operate, it would have a material adverse effect on our ability to economically find and develop crude oil and natural gas reserves in our strategic plays. The inability to achieve a satisfactory economic return could cause us to curtail or discontinue our exploration and development plans, which would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Proposed changes to existing laws or regulations or changes in interpretations of laws and regulations under consideration could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.

Changes to existing laws or regulations, new laws or regulations, or changes in interpretations of laws and regulations may unfavorably impact us or the infrastructure used for transporting our products. Similarly, changes in regulatory policies and priorities could result in the imposition of new obligations upon us, such as increased reporting or audits. Any of these requirements could result in increased operating costs and could have a material adverse effect on our financial condition and results of operations. If such legislation, regulations or interpretations are adopted, they could result in, among other items, additional restrictions on hydraulic fracturing of wells, restrictions on the disposal of waste water from oil and gas activities, restrictions on emissions of greenhouse gases, modification of equipment utilized in our operations, changes to the calculation of royalty payments, new safety requirements such as those involving rail transportation, and additional regulation of private energy commodity derivative and hedging activities. These and other potential laws, regulations, interpretations and other requirements could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. This, in turn, could have a material adverse effect on our financial condition, results of operations and cash flows.

Certain aspects of the newly enacted federal income tax reform legislation in the United States could adversely affect us.

On December 22, 2017, the Tax Cuts and Jobs Act (the "Tax Reform Act") was signed into law by President Trump. The Tax Reform Act represents the most significant tax policy change in the United States since 1986 and includes, among others, the following key changes to federal tax law:

- Reduces the corporate tax rate from 35% to 21% and eliminates the corporate alternative minimum tax;
- Limits the tax deduction for certain net operating loss (NOL) carryforwards to 80% of taxable income for a taxable year, allows NOLs generated in years after December 31, 2017 to be carried forward indefinitely, and repeals NOL carrybacks;
- Limits the tax deduction for business interest expense to 30% of adjusted taxable income for a taxable year;
- Allows businesses to immediately expense the cost of new investments in certain qualified depreciable assets;
- Creates a territorial tax system rather than a worldwide system, which generally allows companies to repatriate future foreign source earnings without incurring additional U.S. taxes;
- Subjects foreign earnings on which U.S. income tax is currently deferred to a one-time transition tax; and
- Eliminates or reduces certain deductions, exclusions, and credits and adds other provisions that broaden the tax base.

Changes arising from the Tax Reform Act, which are subject to a number of important qualifications and exceptions, generally become effective for tax years beginning after December 31, 2017. Certain of the changes are permanent, while others expire at specified dates. The Tax Reform Act's provisions could have state and local tax implications. While some states automatically adopt federal tax law changes, others conform their laws with federal law on specific dates. States also may choose to decouple from the new federal tax provisions and continue to apply previous law.

Apart from the future benefits to be realized from the reduction in the corporate income tax rate from 35% to 21%, the overall long-term impact of other aspects of the Tax Reform Act is uncertain, and our business, financial condition, results of operations and cash flows could be adversely affected by certain new provisions, particularly the limitations on the tax deductibility of business interest expense and NOLs. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations–Legislative and Regulatory Developments–Tax Reform Legislation for a forward-looking discussion of the potential impact of the Tax Reform Act.

In previous years, legislation has been proposed to eliminate or defer certain key U.S. federal income tax deductions historically available to oil and gas exploration and production companies. Such proposed changes have included: (i) a repeal of the percentage depletion allowance for crude oil and natural gas properties; (ii) the elimination of deductions for intangible drilling and exploration and development costs; (iii) the elimination of the deduction for certain production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. These tax deductions currently utilized within our industry are not impacted by the Tax Reform Act. However, no prediction can be made as to whether any legislative changes will be proposed or enacted in the future that could eliminate or defer these or other tax deductions utilized within our industry.

Competition in the crude oil and natural gas industry is intense, making it more difficult for us to acquire properties, market crude oil and natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, securing long-term transportation and processing capacity, marketing crude oil and natural gas, and securing trained personnel. Also, there is substantial competition for capital available for investment in the crude oil and natural gas industry. Certain of our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for productive crude oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, securing long-term transportation and processing capacity, marketing hydrocarbons, attracting and retaining quality personnel, and raising additional capital, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.
Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, oil spills, induced seismicity, and greenhouse gas emissions may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and

enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to conduct our business.

Energy conservation measures or initiatives that stimulate demand for alternative forms of energy could reduce the demand for the crude oil and natural gas we produce.

Fuel conservation measures, climate change initiatives, governmental requirements for renewable energy resources, increasing consumer demand for alternative forms of energy, and technological advances in fuel economy and energy generation devices could reduce demand for the crude oil and natural gas we produce. The potential impact of changing demand for crude oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Severe weather events and natural disasters could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Severe weather events and natural disasters such as hurricanes, tornadoes, seismic events, blizzards and ice storms affecting the areas in which we operate, including our corporate headquarters, could have a material adverse effect on our operations or the operations of third party service providers. Such events may result in significant destruction of infrastructure, businesses, and homes and could disrupt the distribution and supply of crude oil and natural gas products in the impacted region. The consequences of such events may include the evacuation of personnel; damage to and disruption of drilling rigs or transportation, processing, storage and refining facilities; the shut-in of production resulting from an inability to transport crude oil or natural gas products to market centers and other factors; an inability to access well sites; destruction of information and communication systems; and the disruption of administrative and management processes, any of which could hinder our ability to conduct normal operations and could adversely affect our business, financial condition, results of operations or cash flows.

Regulations under the Dodd-Frank Act regarding derivatives could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risk and other risks associated with our business.

From time to time, we may use derivative instruments to manage commodity price risk. In 2010, the U.S. Congress adopted the Dodd-Frank Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. This financial reform legislation includes provisions that require many derivative transactions previously executed over-the-counter to be executed through an exchange and be centrally cleared. In addition, this legislation calls for the imposition of position limits for swaps, including swaps involving physical commodities such as crude oil and natural gas, which have been proposed but have not been finalized. It also establishes minimum margin requirements for uncleared swaps for swap dealers and major swap participants.

If we do not qualify for an end user exemption from the Dodd-Frank requirements, the new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, lead to fewer potential counterparties, impose new recordkeeping and documentation requirements, and increase our exposure to less creditworthy counterparties. Additionally, the proposed position limits may limit our ability to implement price risk management strategies if we are not able to qualify for any exemption from such limits. Further, if we do not qualify for an end user exemption, the margin requirements for uncleared swaps may require us to post collateral, which could adversely affect our available liquidity. If our use of derivatives becomes limited as a result of the regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower crude oil or natural gas prices. Any of these consequences could have a material adverse effect on our financial position, results of operations and cash flows.

The loss of senior management or technical personnel could adversely affect our operations.

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Harold G. Hamm, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an ownership interest are operated by other companies and involve third-party working interest owners. As of December 31, 2017, non-operated properties represented 18% of our estimated proved developed reserves, 6% of our estimated proved undeveloped reserves, and 11% of our estimated total proved reserves. We have limited ability to influence or control the operations or future development of non-operated properties, including compliance with environmental, safety and other regulations, or the amount of expenditures required to fund the development and operation of such properties. Moreover, we are dependent on other working interest owners on these projects to fund their contractual share of capital and operating expenditures. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

Our revolving credit facility and indentures for our senior notes contain certain covenants and restrictions that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our goals.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, and merge, consolidate or sell all or substantially all of our assets. Our revolving credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders’ equity plus, to the extent resulting in a reduction of total shareholders’ equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014.

At December 31, 2017, our consolidated net debt to total capitalization ratio, as defined, was 0.51 to 1.00. Our total debt would need to independently increase by approximately $5.2 billion above the existing level at December 31, 2017 (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders’ equity would need to independently decrease by approximately $2.8 billion below the existing level at December 31, 2017 (excluding the after-tax impact of any non-cash impairment charges) to reach the maximum covenant ratio.

The indentures governing our senior notes contain covenants that, among other things, limit our ability to create liens securing certain indebtedness, enter into certain sale and leaseback transactions, and consolidate, merge or transfer certain assets.

The covenants in our revolving credit facility and senior note indentures may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our revolving credit facility or senior note indentures may be impacted by changes in economic or business conditions, results of operations, or events beyond our control. The breach of any of these covenants could result in a default under our revolving credit facility or senior note indentures, in which case, depending on the actions taken by the lenders or trustees thereunder or their successors or assignees, could result in all amounts outstanding thereunder, together with accrued interest, to be due and payable. If our indebtedness is accelerated, our assets may not be sufficient to repay in full such indebtedness, which would adversely affect our financial condition and results of operations.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

Our business and industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, analyze seismic and drilling information, conduct reservoir modeling and reserves estimation, communicate with employees and business associates, perform compliance reporting and many other activities related to our business. Our business associates, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. Our technologies, systems, networks, and those of our business associates have been and may continue to be the target of cyber attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release or theft of confidential or protected information, corruption of data or other disruptions of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber attack involving our information systems and related infrastructure, or that of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including but not limited to:

- unauthorized access to or theft of seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- data corruption or operational disruption of production-related infrastructure could result in a loss of production, or accidental discharge;
- a cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects; and
- a cyber attack on third party transportation, processing, storage or refining facilities could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business, or potential liability, which could have a material adverse effect on our financial condition, results of operations or cash flows.

To our knowledge we have not experienced any material losses relating to cyber attacks; however, there can be no assurance that we will not suffer material losses in the future. 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.

Increases in interest rates could adversely affect our business.

The U.S. Federal Reserve increased the benchmark federal funds interest rate on three separate occasions in 2017 and is forecasting additional increases in 2018 and 2019. Our business and operating results can be adversely affected by increases in interest rates, the availability, terms of and cost of capital, or downgrades or other negative rating actions with respect to our credit rating. These factors could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flows used for drilling and place us at a competitive disadvantage. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our financial condition and results of operations.

The inability of joint interest owners, derivative counterparties, significant customers, and service providers to meet their obligations to us may adversely affect our financial results.

Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies ($672 million in receivables at December 31, 2017); our joint interest and other receivables ($427 million at December 31, 2017); and counterparty credit risk associated with our derivative instrument receivables ($3 million at December 31, 2017).

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells.

We are also subject to credit risk due to concentration of our crude oil and natural gas receivables with significant customers. The two largest purchasers of our crude oil and natural gas during the year ended December 31, 2017 accounted for approximately 11% and 11%, respectively, of our total crude oil and natural gas revenues for the year. We have not generally required our counterparties to provide collateral to secure crude oil and natural gas sales receivables owed to us. Additionally, our use of derivative instruments involves the risk that our counterparties will be unable to meet their obligations.

Finally, we rely on oilfield service companies and midstream companies for services associated with the drilling and completion of wells and for certain midstream services. A worsening of the commodity price environment may result in a material adverse impact on the liquidity and financial position of the parties with whom we do business, resulting in delays in payment of, or non-payment of, amounts owed to us, delays in operations, loss of access to equipment and facilities and similar impacts. These events could have an adverse impact on our financial condition, results of operations and cash flows.

Our derivative activities could result in financial losses or reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in commodity prices, from time to time we may enter into derivative instruments for a portion of our production. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 5. Derivative Instruments for a summary of our commodity derivative

positions as of December 31, 2017. We do not designate any of our derivative instruments as hedges for accounting purposes and we record all derivatives on our balance sheet at fair value. Changes in the fair value of our derivatives are recognized in current period earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in commodity prices and resulting changes in the fair value of our derivatives.
Derivative instruments expose us to the risk of financial loss in certain circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, our derivative arrangements limit the benefit we would receive from increases in commodity prices. Our decision on the quantity and price at which we choose to hedge our future production, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to hedge future production if the pricing environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program.

We have hedged the majority of our forecasted 2018 natural gas production. Our future crude oil production is currently unhedged and directly exposed to continued volatility in market prices, whether favorable or unfavorable.

Our Chairman and Chief Executive Officer beneficially owns approximately 76% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our Company.

As of December 31, 2017, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owned approximately 76% of our outstanding common shares. As a result, Mr. Hamm has control over our Company and will continue to be able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other shareholders, the outcome of certain corporate transactions or other matters submitted to our shareholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. Therefore, Mr. Hamm could cause, delay or prevent a change of control of our Company. The interests of Mr. Hamm may not coincide with the interests of other holders of our common stock.

We have historically entered into, and may enter into, transactions from time to time with companies affiliated with Mr. Hamm if, after an independent review by our Audit Committee or by the independent members of our Board of Directors, it is determined such transactions are in the Company’s best interests and are on terms no less favorable to us than could be achieved with an unaffiliated third party. These transactions may result in conflicts of interest between Mr. Hamm’s affiliated companies and us.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in new or emerging areas are more uncertain than drilling results in developed and producing areas. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We may be subject to risks in connection with acquisitions, divestitures, and joint development arrangements.

As part of our business strategy, we have made and will likely continue to make acquisitions of oil and gas properties, divest of non-strategic assets, and enter into joint development arrangements. Suitable acquisition properties, buyers of our non-strategic assets, or joint development counterparties may not be available on terms and conditions we find acceptable or not at all.

The successful acquisition of producing properties requires an assessment of several factors, including but not limited to:

- recoverable reserves;
- future crude oil and natural gas prices and location and quality differentials;
- the quality of the title to acquired properties;
- future development costs, operating costs and property taxes; and
- potential environmental and other liabilities.

The accuracy of these acquisition assessments is inherently uncertain. In connection with these assessments, we perform a review, which we believe to be generally consistent with industry practices, of the subject properties. 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 prior to acquisition. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller of the subject properties may be unwilling or unable to provide effective contractual protection against all or part of the problems. We sometimes are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis.

In addition, from time to time we may sell or otherwise dispose of certain non-strategic assets as a result of an evaluation of our asset portfolio or to provide cash flow for use in reducing debt and enhancing liquidity. Such divestitures have inherent risks, including possible delays in closing, the risk of lower-than-expected sales proceeds for the disposed assets, and potential post-closing adjustments and claims for indemnification. Additionally, volatility and unpredictability in commodity prices may result in fewer potential bidders, unsuccessful sales efforts, and a higher risk that buyers may seek to terminate a transaction prior to closing.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that infrastructure we rely on could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2017.

Item 2. Properties

The information required by Item 2 is contained in Part I, Item 1. Business—Crude Oil and Natural Gas Operations and is incorporated herein by reference.

Item 3. Legal Proceedings

See Note 10. Commitments and Contingencies–Litigation in Part II, Item 8. Financial Statements and Supplementary Data–Notes to Consolidated Financial Statements for a discussion of the legal matter involving the Company, Billy J. Strack and Daniela A. Renner, which is incorporated herein by reference.

We have received Notices of Violation from the North Dakota Department of Health (“NDDH”) alleging violations of the state’s air quality and water pollution control laws and rules. We exchanged information and engaged in discussions with NDDH aimed at resolving the allegations and anticipate further discussions and exchanges. Resolution of the allegations may result in monetary sanctions of more than $100,000.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

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

Our common stock is listed on the New York Stock Exchange and trades under the symbol "CLR." The following table sets forth quarterly high and low sales prices for each quarter of the previous two years. No cash dividends were declared during the previous two years.

| | 2017 Quarter Ended | | | | 2016 Quarter Ended | | | |
|---|---|---|---|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 | March 31 | June 30 | September 30 | December 31 |
| High | $53.57 | $47.87 | $ 40.03 | $ 53.55 | $31.90 | $46.01 | $ 52.78 | $ 60.30 |
| Low | $41.28 | $30.18 | $ 29.08 | $ 36.05 | $13.94 | $28.63 | $ 40.92 | $ 44.37 |
| Cash Dividend | — | — | — | — | — | — | — | — |

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. As of January 31, 2018, the number of record holders of our common stock was 1,146. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 64,400. On January 31, 2018, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $55.53 per share.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2017:

| Period | Total number of shares purchased (1) | Average price paid per share (2) | Total number of shares purchased as part of publicly announced plans or programs | Maximum number of shares that may yet be purchased under the plans or programs |
|---|---|---|---|---|
| October 1, 2017 to October 31, 2017 | 234 | $ 38.24 | — | — |
| November 1, 2017 to November 30, 2017 | 18,435 | $ 44.84 | — | — |
| December 1, 2017 to December 31, 2017 | — | — | — | — |
| Total | 18,669 | $ 44.76 | — | — |

(1) In connection with restricted stock grants under the Company's 2013 Long-Term Incentive Plan ("2013 Plan"), we adopted a policy that enables employees to surrender shares to cover their tax liability. Shares indicated as having been purchased in the table above represent shares surrendered by employees to cover tax liabilities. We paid the associated taxes to the applicable taxing authorities.

(2) The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares.

Equity Compensation Plan Information

The following table sets forth the information as of December 31, 2017 relating to equity compensation plans:

| | Number of Shares to be Issued Upon Exercise of Outstanding Options | Weighted-Average Exercise Price of Outstanding Options | Remaining Shares Available for Future Issuance Under Equity Compensation Plans (1) |
|---|---|---|---|
| Equity Compensation Plans Approved by Shareholders | — | — | 14,538,540 |
| Equity Compensation Plans Not Approved by Shareholders | — | — | — |

(1) Represents the remaining shares available for issuance under the 2013 Plan.

Performance Graph

The following graph compares our common stock performance with the performance of the Standard & Poor's 500 Stock Index ("S&P 500 Index") and the Dow Jones US Oil and Gas Index ("Dow Jones US O&G Index") for the period of December 31, 2012 through December 31, 2017. The graph assumes the value of the investment in our common stock and in each index was $100 on December 31, 2012 and that any dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.

The information provided in this section is being furnished to, and not filed with, the SEC. As such, this information is neither subject to Regulation 14A or 14C nor to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

Item 6. Selected Financial Data

This section presents selected consolidated financial data for the years ended December 31, 2013 through 2017. The selected financial data presented below is not intended to replace our consolidated financial statements.

The following consolidated financial data has been derived from our audited consolidated financial statements for such periods. You should read the following selected financial data in connection with Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes included elsewhere in this report. The selected consolidated results are not necessarily indicative of results to be expected in future periods.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2014 | 2013 |
| Income Statement data | | | | | |
| In thousands, except per share data | | | | | |
| Crude oil and natural gas sales | $2,982,966 | $2,026,958 | $2,552,531 | $4,203,022 | $3,573,431 |
| Gain (loss) on crude oil and natural gas derivatives, net (1) | 91,647 | (71,859) | 91,085 | 559,759 | (191,751) |
| Total revenues | 3,120,828 | 1,980,273 | 2,680,167 | 4,801,618 | 3,421,807 |
| Income (loss) from continuing operations (2) | 789,447 | (399,679) | (353,668) | 977,341 | 764,219 |
| Net income (loss) (2) | 789,447 | (399,679) | (353,668) | 977,341 | 764,219 |
| Basic net income (loss) per share: | | | | | |
| From continuing operations | $2.13 | $(1.08) | $(0.96) | $2.65 | $2.08 |
| Net income (loss) per share | $2.13 | $(1.08) | $(0.96) | $2.65 | $2.08 |
| Shares used in basic income (loss) per share | 371,066 | 370,380 | 369,540 | 368,829 | 368,150 |
| Diluted net income (loss) per share: | | | | | |
| From continuing operations | $2.11 | $(1.08) | $(0.96) | $2.64 | $2.07 |
| Net income (loss) per share | $2.11 | $(1.08) | $(0.96) | $2.64 | $2.07 |
| Shares used in diluted income (loss) per share | 373,768 | 370,380 | 369,540 | 370,758 | 369,698 |
| Production volumes | | | | | |
| Crude oil (MBbl) (3) | 50,536 | 46,850 | 53,517 | 44,530 | 34,989 |
| Natural gas (MMcf) | 228,159 | 195,240 | 164,454 | 114,295 | 87,730 |
| Crude oil equivalents (MBoe) | 88,562 | 79,390 | 80,926 | 63,579 | 49,610 |
| Sales volumes | | | | | |
| Crude oil (MBbl) (3) | 50,628 | 46,802 | 53,664 | 44,122 | 34,985 |
| Natural gas (MMcf) | 228,159 | 195,240 | 164,454 | 114,295 | 87,730 |
| Crude oil equivalents (MBoe) | 88,655 | 79,342 | 81,073 | 63,172 | 49,607 |
| Average sales prices (4) | | | | | |
| Crude oil ($/Bbl) | $45.70 | $35.51 | $40.50 | $81.26 | $89.93 |
| Natural gas ($/Mcf) | $2.93 | $1.87 | $2.31 | $5.40 | $4.87 |
| Crude oil equivalents ($/Boe) | $33.65 | $25.55 | $31.48 | $66.53 | $72.04 |
| Average costs per unit (4) | | | | | |
| Production expenses ($/Boe) | $3.66 | $3.65 | $4.30 | $5.58 | $5.69 |
| Production taxes (% of oil and gas revenues) | 7.0% | 7.0% | 7.8% | 8.2% | 8.3% |
| DD&A ($/Boe) | $18.89 | $21.54 | $21.57 | $21.51 | $19.47 |
| General and administrative expenses ($/Boe) (5) | $2.16 | $2.14 | $2.34 | $2.92 | $2.91 |
| Proved reserves at December 31 | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Crude oil (MBbl) | 640,949 | 643,228 | 700,514 | 866,360 | 737,788 |
| Natural gas (MMcf) | 4,140,281 | 3,789,818 | 3,151,786 | 2,908,386 | 2,078,020 |
| Crude oil equivalents (MBoe) | 1,330,995 | 1,274,864 | 1,225,811 | 1,351,091 | 1,084,125 |
| Other financial data (in thousands) | | | | | |
| Net cash provided by operating activities | $2,079,106 | $1,125,919 | $1,857,101 | $3,355,715 | $2,563,295 |
| Net cash used in investing activities | $(1,808,845 ) | $(532,965 ) | $(3,046,247 ) | $(4,587,399 ) | $(3,711,011 ) |
| Net cash (used in) provided by financing activities | $(243,034 ) | $(587,773 ) | $1,187,189 | $1,227,715 | $1,140,469 |
| Total capital expenditures | $2,035,254 | $1,110,256 | $2,564,301 | $5,015,595 | $3,841,633 |
| Balance Sheet data at December 31 (in thousands) | | | | | |
| Total assets | $14,199,651 | $13,811,776 | $14,919,808 | $15,076,033 | $11,841,567 |
| Long-term debt, including current portion | $6,353,691 | $6,579,916 | $7,117,788 | $5,928,878 | $4,650,889 |
| Shareholders' equity | $5,131,203 | $4,301,996 | $4,668,900 | $4,967,844 | $3,953,118 |

(1) Crude oil and natural gas derivative instruments are not designated as hedges for accounting purposes and, therefore, changes in the fair value of the instruments are shown separately from crude oil and natural gas sales. The amounts above include non-cash mark-to-market gains (losses) on crude oil and natural gas derivatives of $62.1 million, ($160.7) million, $21.5 million, $174.4 million, and ($130.2) million for the years ended December 31, 2017, 2016, 2015, 2014, and 2013, respectively. Additionally, 2014 includes $433 million of gains recognized from crude oil derivative contracts that were settled in the fourth quarter of 2014 prior to their contractual maturities initially scheduled through December 2016.

(2) Results for 2017 reflect the remeasurement of the Company's deferred income tax assets and liabilities in response to the enactment of the Tax Cuts and Jobs Act in December 2017, which resulted in a one-time increase in net income of approximately $713.7 million ($1.92 per basic share and $1.91 per diluted share). See Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Income Taxes for further discussion. Additionally, 2017 results include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement as discussed in Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies, which resulted in an after-tax decrease in 2017 net income of $37.0 million ($0.10 per basic and diluted share).

(3) At various times, we have stored crude oil due to pipeline line fill requirements, low commodity prices, or marketing disruptions or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes.

(4) Average sales prices and average costs per unit have been computed using sales volumes and exclude any effect of derivative transactions.

(5) General and administrative (“G&A”) expenses ($/Boe) include non-cash equity compensation expenses of $0.52 per Boe, $0.61 per Boe, $0.64 per Boe, $0.86 per Boe, and $0.80 per Boe for the years ended December 31, 2017, 2016, 2015, 2014, and 2013, respectively.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes, as well as the selected consolidated financial data included elsewhere in this report. Our operating results for the periods discussed below may not be indicative of future performance. For additional discussion of crude oil and natural gas reserve information, please see Part I, Item 1. Business—Crude Oil and Natural Gas Operations. The following discussion and analysis includes forward-looking statements and should be read in conjunction with Part I, Item 1A. Risk Factors in this report, along with Cautionary Statement for the Purpose of the “Safe Harbor” Provisions of the Private Securities Litigation Reform Act of 1995 at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are an independent crude oil and natural gas company engaged in the exploration, development and production of crude oil and natural gas. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas and expect this to continue in the future. Our operations are primarily focused on exploration and development activities in the Bakken field of North Dakota and Montana and the SCOOP and STACK areas of Oklahoma.

Business Environment and Outlook

Continental marked its 50th anniversary in the oil and gas business in 2017. Our leadership team has significant experience with operating in challenging commodity price environments. Commodity prices remained volatile during the year, but generally increased on average in 2017 relative to 2016. Crude oil prices in particular showed significant signs of improvement in late 2017 and early 2018, with West Texas Intermediate crude oil benchmark prices reaching a three-year high of $66 per barrel in January 2018. With our portfolio of high quality assets, we are well-positioned to manage the ongoing challenges and price volatility facing our industry.

For 2018, our primary business strategies will focus on:

- Balancing strong production growth with free cash flow generation;
- Enhancing cash flows and return on capital employed through improvements in operating efficiencies, technical innovations, and optimized completion methods;
- Continuing to exercise disciplined capital spending to maintain financial flexibility and ample liquidity; and
- Improving debt metrics by further reducing outstanding debt using available operating cash flows or proceeds from asset dispositions or joint development arrangements.

Based on an expectation for higher operating cash flows in 2018, we have increased our planned non-acquisition capital spending for 2018 to $2.3 billion compared to $2.0 billion spent in 2017, with approximately 78% of our 2018 drilling and completion budget focusing on oil-weighted areas in the North Dakota Bakken and SCOOP Springer plays. We expect to fund our budgeted spending using cash flows from operations. We may adjust our pace of drilling and development as 2018 market conditions evolve.

2017 Highlights

Production

Crude oil and natural gas production averaged 242,637 Boe per day in 2017, an increase of 12% compared to 2016. Total production for the fourth quarter of 2017 averaged 286,985 Boe per day, an increase of 18% compared to the third quarter of 2017 and 37% higher than the fourth quarter of 2016.

Average daily crude oil production increased 8% in 2017 compared to 2016 while average daily natural gas production increased 17%.

Crude oil represented 57% of our 2017 production compared to 59% for 2016. Crude oil represented 59% of our production for the fourth quarter of 2017 compared to 58% for the third quarter of 2017 and 55% for the fourth quarter of 2016.

The following table summarizes the changes in our average daily Boe production by major operating area for the periods presented.

| | Fourth Quarter | | | Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| Boe production per day | 2017 | 2016 | % Change | 2017 | 2016 | % Change |
| Bakken | 165,598 | 104,524 | 58 % | 132,992 | 119,200 | 12 % |
| SCOOP | 62,242 | 63,490 | (2 %) | 60,693 | 65,062 | (7 %) |
| STACK | 47,914 | 24,426 | 96 % | 36,220 | 16,983 | 113 % |
| All other | 11,231 | 17,421 | (36 %) | 12,732 | 15,667 | (19 %) |
| Total | 286,985 | 209,861 | 37 % | 242,637 | 216,912 | 12 % |

Revenues

Crude oil and natural gas revenues totaled $2.98 billion for 2017, a 47% increase compared to 2016 driven by a 32% increase in realized commodity prices coupled with a 12% increase in total sales volumes.

Crude oil and natural gas revenues totaled $1.02 billion for the 2017 fourth quarter, a 44% increase from the 2017 third quarter and 72% higher than the 2016 fourth quarter, reflecting an increase in well completion activities and improvement in commodity prices and price realizations in late 2017. Total sales volumes for the 2017 fourth quarter increased 20% and 38% and realized commodity prices increased 20% and 25% compared to the 2017 third quarter and 2016 fourth quarter, respectively.

Proved reserves

At December 31, 2017, our proved reserves totaled 1,331 MMBoe, an increase of 4% from proved reserves of 1,275 MMBoe at December 31, 2016.

Extensions and discoveries from our drilling and completion activities added 240 MMBoe of proved reserves in 2017 and upward reserve revisions due to improved commodity prices increased reserves by 42 MMBoe. These increases were partially offset by 89 MMBoe of production during the year and net downward reserve revisions totaling 124 MMBoe resulting from changes in drilling plans and other factors.

The following table summarizes the changes in our proved reserves by major operating area in 2017:

| | December 31, 2017 | | December 31, 2016 | | Volume change | Volume percent change |
|---|---|---|---|---|---|---|
| Proved reserves by area | MBoe | Percent | MBoe | Percent | | |
| Bakken | 635,521 | 48 % | 591,901 | 46 % | 43,620 | 7 % |
| SCOOP | 491,776 | 37 % | 471,921 | 37 % | 19,855 | 4 % |
| STACK | 167,390 | 13 % | 161,243 | 13 % | 6,147 | 4 % |
| All Other | 36,308 | 2 % | 49,799 | 4 % | (13,491) | (27 %) |
| Total | 1,330,995 | 100 % | 1,274,864 | 100 % | 56,131 | 4 % |

Operating cash flows

Cash flows from operating activities totaled $2.08 billion for 2017, an increase of 85% compared to $1.13 billion for 2016, reflecting an increase in sales volumes and improvement in commodity prices and price realizations in 2017.

Capital expenditures and drilling activity

Full year 2017 non-acquisition capital expenditures totaled approximately $2.00 billion compared to $1.07 billion for 2016, reflecting our planned increase in spending for 2017 in response to improved commodity prices.

In 2017 we participated in the drilling and completion of 608 gross (214 net) wells compared to 365 gross (92 net) wells in 2016.

2017 property dispositions

In September 2017 we sold non-strategic properties in the Arkoma Woodford area of Oklahoma for cash proceeds of $65.3 million. The sale included approximately 26,000 net acres of leasehold and producing properties with production totaling approximately 1,700 Boe per day. In connection with the transaction, we recognized a pre-tax loss of $3.5 million for the year ended December 31, 2017.

In September 2017, we reached an agreement to sell non-core leasehold in the STACK play in Blaine County, Oklahoma for cash proceeds totaling $63.5 million. A portion of the transaction closed in September 2017, resulting in the receipt of proceeds amounting to $3.6 million and the recognition of a $3.3 million pre-tax gain on sale in the 2017 third quarter. The remainder of the transaction was completed in October 2017 at which time we received the remaining $59.9 million of proceeds and recognized an additional pre-tax gain of approximately $53.6 million, which is reflected in fourth quarter 2017 results.

In September 2017, we sold certain oil-loading facilities in Oklahoma for $7.2 million and recognized a $4.2 million pre-tax gain for the year ended December 31, 2017 associated with the transaction.

Debt and liquidity

Total debt decreased $226 million, or 3%, to $6.35 billion at December 31, 2017 compared to $6.58 billion at year-end 2016.

In December 2017 we issued $1.0 billion of 4.375% Senior Notes due 2028 (“2028 Notes”) and received total net proceeds of $990 million after deducting the initial purchasers’ fees. We used the proceeds from the offering to repay in full and terminate our $500 million term loan due November 4, 2018 and to repay a portion of the borrowings outstanding under our revolving credit facility, thereby resulting in enhanced liquidity.

At December 31, 2017, we had $43.9 million of cash and cash equivalents and $2.56 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $188 million of credit facility borrowings at December 31, 2017 compared to $938 million at September 30, 2017 and $905 million at December 31, 2016. At January 31, 2018, outstanding credit facility borrowings decreased further to $93 million, leaving approximately $2.65 billion of borrowing availability at that date.

Impact of income tax reform legislation

In December 2017, the Tax Cuts and Jobs Act (the "Tax Reform Act") was signed into law, which among other things reduces the federal corporate income tax rate from 35% to 21% effective January 1, 2018. In accordance with U.S. GAAP, we remeasured our deferred income tax assets and liabilities as of December 31, 2017 to reflect the reduced tax rate, which resulted in a one-time decrease in income tax expense and corresponding increase in net income of approximately $713.7 million ($1.92 per basic share and $1.91 per diluted share) recognized in the 2017 fourth quarter. See the subsequent section titled Legislative and Regulatory Developments–Tax Reform Legislation and Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Income Taxes for further discussion of the Tax Reform Act.

Litigation settlement

On February 16, 2018, we reached a settlement in connection with the case filed in November 2010 in the District Court of Blaine County by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. Under the settlement, if approved by the court, we will make payments and incur costs associated with the settlement of approximately $59.6 million. We have accrued a loss for such amount, which is included in “Accrued liabilities and other” on the consolidated balance sheets and “Litigation settlement” in the consolidated statements of comprehensive income (loss) as of and for the year ended December 31, 2017, which resulted in an after-tax decrease in 2017 net income of $37.0 million ($0.10 per basic and diluted share). See Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies for further discussion.

Financial and operating highlights

We use a variety of financial and operating measures to assess our performance. Among these measures are:

- Volumes of crude oil and natural gas produced;
- Crude oil and natural gas price differentials relative to NYMEX benchmark prices; and
- Per unit operating and administrative costs.

The following table contains financial and operating highlights for the periods presented. Average sales prices exclude any effect of derivative transactions. Per-unit expenses have been calculated using sales volumes.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Average daily production: | | | |
| Crude oil (Bbl per day) | 138,455 | 128,005 | 146,622 |
| Natural gas (Mcf per day) | 625,093 | 533,442 | 450,558 |
| Crude oil equivalents (Boe per day) | 242,637 | 216,912 | 221,715 |
| Average sales prices: | | | |
| Crude oil ($/Bbl) | $45.70 | $35.51 | $40.50 |
| Natural gas ($/Mcf) | $2.93 | $1.87 | $2.31 |
| Crude oil equivalents ($/Boe) | $33.65 | $25.55 | $31.48 |
| Crude oil sales price discount to NYMEX ($/Bbl) | $(5.50 ) | $(7.33 ) | $(8.33 ) |
| Natural gas sales price discount to NYMEX ($/Mcf) | $(0.16 ) | $(0.61 ) | $(0.34 ) |
| Production expenses ($/Boe) | $3.66 | $3.65 | $4.30 |
| Production taxes (% of oil and gas revenues) | 7.0 % | 7.0 % | 7.8 % |
| DD&A ($/Boe) | $18.89 | $21.54 | $21.57 |
| Total general and administrative expenses ($/Boe) | $2.16 | $2.14 | $2.34 |

Results of Operations

The following table presents selected financial and operating information for the periods presented.

| In thousands, except sales price data | Year Ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|
| Crude oil and natural gas sales | $2,982,966 | $2,026,958 | $2,552,531 |
| Gain (loss) on crude oil and natural gas derivatives, net | 91,647 | (71,859) | 91,085 |
| Crude oil and natural gas service operations | 46,215 | 25,174 | 36,551 |
| Total revenues | 3,120,828 | 1,980,273 | 2,680,167 |
| Operating costs and expenses (1) | (2,671,427) | (2,267,807) | (2,904,168) |
| Other expenses, net (2) | (293,334) | (344,920) | (311,084) |
| Income (loss) before income taxes | 156,067 | (632,454) | (535,085) |
| Benefit for income taxes (3) | 633,380 | 232,775 | 181,417 |
| Net income (loss) | $789,447 | $(399,679) | $(353,668) |
| Diluted net income (loss) per share | $2.11 | $(1.08) | $(0.96) |
| Production volumes: | | | |
| Crude oil (MBbl) | 50,536 | 46,850 | 53,517 |
| Natural gas (MMcf) | 228,159 | 195,240 | 164,454 |
| Crude oil equivalents (MBoe) | 88,562 | 79,390 | 80,926 |
| Sales volumes: | | | |
| Crude oil (MBbl) | 50,628 | 46,802 | 53,664 |
| Natural gas (MMcf) | 228,159 | 195,240 | 164,454 |
| Crude oil equivalents (MBoe) | 88,655 | 79,342 | 81,073 |
| Average sales prices: | | | |
| Crude oil ($/Bbl) | $45.70 | $35.51 | $40.50 |
| Natural gas ($/Mcf) | $2.93 | $1.87 | $2.31 |
| Crude oil equivalents ($/Boe) | $33.65 | $25.55 | $31.48 |

(1) Net of gain on sale of assets of $55.1 million, $304.5 million and $23.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. Additionally, the year 2017 includes the aforementioned $59.6 million loss accrual recognized in conjunction with a litigation settlement.

(2) The year 2016 includes a loss on extinguishment of debt of $26.1 million related to the November 2016 redemptions of our $200 million of 7.375% Senior Notes due 2020 and $400 million of 7.125% Senior Notes due 2021.

(3) The year 2017 reflects the remeasurement of our deferred income tax assets and liabilities in response to the enactment of the Tax Reform Act in December 2017, which resulted in a one-time decrease in income tax expense via the recognition of an income tax benefit totaling approximately $713.7 million.

Year ended December 31, 2017 compared to the year ended December 31, 2016

Production

The following tables reflect our production by product and region for the periods presented.

| | Year Ended December 31, 2017 Volume | Percent | 2016 Volume | Percent | Volume increase | Volume percent increase |
|---|---|---|---|---|---|---|
| Crude oil (MBbl) | 50,536 | 57 % | 46,850 | 59 % | 3,686 | 8 % |
| Natural gas (MMcf) | 228,159 | 43 % | 195,240 | 41 % | 32,919 | 17 % |
| Total (MBoe) | 88,562 | 100 % | 79,390 | 100 % | 9,172 | 12 % |

| | Year Ended December 31, 2017 | | 2016 | | Volume increase | Volume percent increase |
|---|---|---|---|---|---|---|
| | MBoe | Percent | MBoe | Percent | | |
| North Region | 52,258 | 59 % | 48,169 | 61 % | 4,089 | 8 % |
| South Region | 36,304 | 41 % | 31,221 | 39 % | 5,083 | 16 % |
| Total | 88,562 | 100 % | 79,390 | 100 % | 9,172 | 12 % |

The 8% increase in crude oil production in 2017 compared to 2016 was primarily driven by a 4,241 MBbls, or 13%, increase in production from properties in North Dakota Bakken due to an increase in well completion activities, the timing of production commencing from new pad development projects, and strong initial production results being achieved on new wells resulting from optimized completion technologies. Additionally, production from our South region properties in the STACK play increased 1,614 MBbls, or 104%, from the prior year due to additional wells being completed and producing as a result of an increase in our drilling and completion activities in that area. These increases were partially offset by decreased production from our North region properties in Montana Bakken and the Red River units due to natural declines in production coupled with reduced drilling activities over the past year. Montana Bakken crude oil production decreased 692 MBbls, or 24%, while crude oil production in the Red River units decreased 344 MBbls, or 9%, from the prior year. Additionally, crude oil production in SCOOP decreased 1,081 MBbls, or 16%, due to natural declines in production and limited drilling activities.

The 17% increase in natural gas production in 2017 compared to 2016 was driven by increased production from our properties in the STACK play due to additional wells being completed and producing subsequent to December 31, 2016. Natural gas production in STACK increased 32,342 MMcf, or 116%, over the prior year. Additionally, natural gas production in North Dakota Bakken increased 8,700 MMcf, or 17%, over the prior year in conjunction with the aforementioned increase in crude oil production. These increases were partially offset by reduced production from our SCOOP properties, which decreased 3,469 MMcf, or 3%, along with various other areas in our North and South regions due to natural declines in production and limited drilling activities. Further, natural gas production decreased 1,323 MMcf in 2017 as a result of the sale of substantially all of our Arkoma Woodford properties in September 2017.

The increase in natural gas production as a percentage of our total production from 41% in 2016 to 43% in 2017 primarily resulted from the significant increase in STACK natural gas production due to the increased allocation of capital to that area over the past year. Certain areas in the STACK play produce a higher concentration of natural gas compared to oil-weighted properties in the Bakken. Our crude oil production grew in relative significance in the second half of 2017 as we increased our well completion activities in North Dakota Bakken in response to improved crude oil market prices. Crude oil represented 59% of our production for the fourth quarter of 2017 compared to 55% for the fourth quarter of 2016.

In conjunction with our planned increase in capital spending for 2018, we expect our production will average between 285,000 and 300,000 Boe per day for full year 2018 compared to average daily production of 242,637 Boe per day for 2017.

Revenues

Our revenues consist of sales of crude oil and natural gas, gains and losses resulting from changes in the fair value of our crude oil and natural gas derivative instruments, and revenues associated with crude oil and natural gas service operations.

Crude oil and natural gas sales. Crude oil and natural gas sales for 2017 were $2.98 billion, a 47% increase from sales of $2.03 billion for 2016 due to a 32% increase in realized commodity prices coupled with a 12% increase in total sales volumes.

Our crude oil sales prices averaged $45.70 per barrel for 2017, an increase of 29% compared to $35.51 for 2016 due to higher crude oil market prices and improved price realizations. The differential between NYMEX West Texas Intermediate (“WTI”) calendar month crude oil prices and our realized crude oil prices averaged $5.50 per barrel for 2017 compared to $7.33 for 2016. The improved differential was primarily due to improved realizations resulting from new pipeline takeaway capacity and additional markets becoming available in 2017 for Bakken production, along with the growth in our South region production which typically has lower transportation costs compared to the

Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma. These factors led to a continued improvement in crude oil price realizations throughout 2017. Our crude oil price differentials relative to WTI prices improved to $4.23 per barrel in the fourth quarter.

Our natural gas sales prices averaged $2.93 per Mcf for 2017, a 57% increase compared to $1.87 per Mcf for 2016 due to higher market prices for natural gas and natural gas liquids (“NGLs”) and improved price realizations. The discount between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices improved from $0.61 per Mcf for 2016 to $0.16 per Mcf for 2017. The majority of our natural gas production is sold at our lease locations to midstream purchasers with price realizations impacted by the volume and value of NGLs that purchasers extract from our sales stream. NGL prices have increased over prior year levels in conjunction with increased crude oil prices and other factors, resulting in improved price realizations for our natural gas sales stream, particularly in later months of 2017. Our realized natural gas sales prices averaged $3.30 per Mcf in the 2017 fourth quarter, representing a premium of $0.37 per Mcf over Henry Hub benchmark prices for that period.

Total sales volumes for 2017 increased 9,313 MBoe, or 12%, compared to 2016, reflecting an increase in our pace of drilling and completion activities in 2017. For 2017, our crude oil sales volumes increased 8% compared to 2016 while our natural gas sales volumes increased 17%.

For the 2017 fourth quarter, crude oil and natural gas revenues totaled $1,017.7 million, representing a 44% increase from 2017 third quarter revenues of $704.8 million and a 72% increase from 2016 fourth quarter revenues of $591.8 million. Revenues for the 2017 fourth quarter were favorably impacted by improved commodity prices and price realizations late in the year. Our crude oil sales prices averaged $51.16 per barrel in the 2017 fourth quarter compared to $43.27 for the 2017 third quarter and $42.23 for the 2016 fourth quarter. Our natural gas sales prices averaged $3.30 per Mcf in the 2017 fourth quarter compared to $2.74 for the 2017 third quarter and $2.70 for the 2016 fourth quarter.

New accounting rules governing the recognition and presentation of revenues went into effect on January 1, 2018. The new rules are not expected to have a material effect on the timing of our revenue recognition, but will impact our presentation of revenues and expenses. Historically, we have generally presented our revenues net of transportation costs. The new guidance will result in future revenues and transportation expenses for certain of our operated properties being reported on a gross basis, with no net effect on our results of operations, net income, or cash flows. For the 2017 fourth quarter, we had approximately $53.4 million of transportation–related charges on operated properties included in “Crude oil and natural gas sales”. The amount of future transportation expenses to be reported on a gross basis in our 2018 first quarter results is estimated to be approximately $50 million.

Derivatives. Changes in natural gas prices during 2017 had an overall favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $91.6 million for the year, representing $62.1 million of non-cash gains and $29.5 million of cash gains.

Crude oil and natural gas service operations. Our crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of lower quality reclaimed crude oil. Revenues associated with such activities increased $21.0 million, or 84%, from $25.2 million for 2016 to $46.2 million for 2017 due to an increase in industry production activities and changes in the nature, timing and extent of water handling and recycling activities between periods.

Operating Costs and Expenses

Production expenses. Production expenses increased $34.9 million, or 12%, from $289.3 million for 2016 to $324.2 million for 2017 due to an increase in the number of producing wells and higher workover-related activities aimed at enhancing production from producing properties. Production expenses on a per-Boe basis averaged $3.66 for 2017, consistent with $3.65 per Boe for 2016. Our per-unit production expenses decreased to $3.17 per Boe for the 2017 fourth quarter.

Production taxes. Production taxes increased $65.9 million, or 46%, to $208.3 million in 2017 compared to $142.4 million in 2016 due to higher crude oil and natural gas revenues resulting from increases in sales volumes and commodity prices over the prior year period. Production taxes are generally based on the wellhead values of production and vary by state. Production taxes as a percentage of crude oil and natural gas revenues averaged 7.0% for 2017, consistent with the 2016 average of 7.0%.

Our production tax rate increased in the second half of 2017 relative to the first half and averaged 7.3% for the 2017 fourth quarter. This increase primarily resulted from a significant increase in production and revenues being generated in North Dakota from increased well completions later in the year, which has higher production tax rates compared to Oklahoma. The production tax rate on new wells in North Dakota is currently 10% of crude oil revenues. The production tax rate on Oklahoma wells that commenced production after July 1, 2015 is currently 2% of crude oil and natural gas revenues for the first 36 months of production and 7% thereafter. Additionally, in 2017 new legislation was enacted in Oklahoma that increased the production tax rate from 1% to 4% and again from 4% to 7% on wells that began producing between July 1, 2011 and July 1, 2015. The new 4% tax rate on these wells went into effect on July 1, 2017, which was subsequently increased to 7% effective December 1, 2017, and contributed to an increase in our average production tax rate in the third and fourth quarters of 2017.

Exploration expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. The following table shows the components of exploration expenses for the periods presented.

| | Year ended December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Geological and geophysical costs | $12,217 | $12,106 |
| Exploratory dry hole costs | 176 | 4,866 |
| Exploration expenses | $12,393 | $16,972 |

Depreciation, depletion, amortization and accretion ("DD&A"). Total DD&A decreased $33.8 million, or 2%, to $1.67 billion for 2017 compared to $1.71 billion for 2016 primarily due to an increase in the volume of proved reserves over which costs are depleted as further discussed below, the impact of which was partially offset by an increase in DD&A resulting from higher sales volumes in the current year. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

| | Year ended December 31, | |
|---|---|---|
| $/Boe | 2017 | 2016 |
| Crude oil and natural gas properties | $18.57 | $21.09 |
| Other equipment | 0.25 | 0.37 |
| Asset retirement obligation accretion | 0.07 | 0.08 |
| Depreciation, depletion, amortization and accretion | $18.89 | $21.54 |

Estimated proved reserves are a key component in our computation of DD&A expense. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense increases. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense decreases. Upward revisions to proved reserves over the past year due in part to an improvement in commodity prices contributed to a decrease in our DD&A rate for crude oil and natural gas properties in 2017 compared to 2016. Additionally, improvements in drilling efficiencies and optimized completion technologies over the past year have resulted in a significant improvement in the quantity of proved reserves found and developed per dollar invested, which also contributed to the reduction in our DD&A rate in the current period.

Property impairments. Property impairments totaled $237.4 million for 2017, consistent with $237.3 million of impairments recognized in 2016. Higher proved property impairments in 2017 were offset by lower non-producing property impairments as discussed below.

Proved property impairments totaled $82.3 million for 2017 compared to $2.9 million for 2016. The proved property impairments recognized in 2017, nearly all of which were recognized in the second quarter, were primarily concentrated in the Arkoma Woodford field for which we determined the carrying amount of the field was not recoverable from future cash flows and, therefore, was impaired at June 30, 2017.

Impairments of non-producing properties decreased $79.4 million, or 34%, to $155.0 million in 2017 compared to $234.4 million for 2016. The decrease was due to a lower balance of unamortized leasehold costs in the current year due to property dispositions and reduced land capital expenditures in recent years, along with changes in the timing and magnitude of amortization of undeveloped leasehold costs between periods resulting from changes in the Company's estimates of undeveloped properties not expected to be developed before lease expiration.

General and administrative expenses. Total general and administrative ("G&A") expenses increased $22.1 million, or 13%, to $191.7 million in 2017 from $169.6 million in 2016. Total G&A expenses include non-cash charges for equity compensation of $45.9 million and $48.1 million for 2017 and 2016, respectively, the decrease of which resulted from changes in the timing and magnitude of forfeitures of unvested restricted stock between periods.

G&A expenses other than equity compensation included in the total G&A expense figure above totaled $145.8 million for 2017, an increase of $24.3 million, or 20%, compared to $121.5 million for 2016. This increase was primarily due to an increase in employee compensation and benefits in 2017 in response to the stabilization and improvement in commodity prices over the past year, partially offset by higher overhead recoveries from joint interest owners driven by increased completion activities over the prior period.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

| $/Boe | Year ended December 31, 2017 | 2016 |
|---|---|---|
| General and administrative expenses | $1.64 | $1.53 |
| Non-cash equity compensation | 0.52 | 0.61 |
| Total general and administrative expenses | $2.16 | $2.14 |

Interest expense. Interest expense decreased $26.1 million, or 8%, to $294.5 million in 2017 from $320.6 million in 2016 due to a decrease in weighted average outstanding debt primarily as a result of the November 2016 redemptions of our $200 million of 7.375% 2020 Notes and $400 million of 7.125% 2021 Notes. Our weighted average outstanding long-term debt balance for 2017 was approximately $6.7 billion with a weighted average interest rate of 4.2% compared to $7.1 billion and 4.3% for 2016. The lower interest expense associated with reduced debt was partially offset by higher interest expense being incurred on our variable-rate credit facility and term loan borrowings due to an increase in market interest rates in 2017.

Income Taxes. Our income before income taxes totaled $156.1 million for the year ended December 31, 2017, nearly all of which was generated by our operations in the United States. We provided for income taxes on this amount at a combined federal and state tax rate of 38% of pre-tax income generated in the United States and 25% of immaterial pre-tax losses generated by our operations in Canada. The application of these statutory tax rates to pre-tax earnings, combined with the impact of permanent taxable differences, valuation allowances and tax deficiencies from stock-based compensation, resulted in the recognition of $80.3 million of income tax expense for 2017. Additionally, we remeasured our deferred income tax balances in December 2017 in response to the enactment of the Tax Reform Act, which resulted in a one-time decrease in income tax expense via the recognition of an income tax benefit totaling approximately $713.7 million. Upon combining the tax benefit from this remeasurement with the tax provision recognized on pre-tax earnings from operations, we recognized a net total income tax benefit of $633.4 million for 2017.

The remeasurement event caused a significant inconsistency in the relationship between income tax expense/benefit and pre-tax income and resulted in a negative effective tax rate for 2017. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Income Taxes for further discussion of this and other sources and tax effects of items comprising our effective tax rate for 2017. Also, see the subsequent section titled "Legislative and Regulatory Developments–Tax Reform Legislation" for a forward-looking discussion of the potential impact of the Tax Reform Act on our business.

For the year ended December 31, 2016, we recorded an income tax benefit of $232.8 million, resulting in an effective tax rate of approximately 37% after taking into account permanent taxable differences and valuation allowances.

Year ended December 31, 2016 compared to the year ended December 31, 2015

Production

The following tables reflect our production by product and region for the periods presented.

| | Year Ended December 31, 2016 Volume | Percent | 2015 Volume | Percent | Volume increase (decrease) | Volume percent increase (decrease) |
|---|---|---|---|---|---|---|
| Crude oil (MBbl) | 46,850 | 59 % | 53,517 | 66 % | (6,667 ) | (12 %) |
| Natural Gas (MMcf) | 195,240 | 41 % | 164,454 | 34 % | 30,786 | 19 % |
| Total (MBoe) | 79,390 | 100 % | 80,926 | 100 % | (1,536 ) | (2 %) |

| | Year Ended December 31, 2016 MBoe | Percent | 2015 MBoe | Percent | Volume increase (decrease) | Volume percent increase (decrease) |
|---|---|---|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| North Region | 48,169 | 61 | % | 54,956 | 68 | % | (6,787) | (12%) |
| South Region | 31,221 | 39 | % | 25,970 | 32 | % | 5,251 | 20% |
| Total | 79,390 | 100 | % | 80,926 | 100 | % | (1,536) | (2%) |

The 12% decrease in crude oil production in 2016 compared to 2015 was driven by decreased production from our North region properties in North Dakota Bakken, Montana Bakken, and the Red River units due to natural declines in production, reduced drilling and completion activities, and curtailment of production in those areas in 2016 resulting from low crude oil prices. Additionally, the effects of severe winter weather in North Dakota in late 2016 adversely impacted our production. North Dakota Bakken 2016 crude oil production decreased 5,816 MBbls, or 15%, and Montana Bakken production decreased 1,090 MBbls, or 28%, while production in the Red River units decreased 543 MBbls, or 13%, from the prior year. Additionally, 2016 crude oil production in SCOOP decreased 390 MBbls, or 5%, resulting from a shift in our activities to liquids-rich natural gas areas of that play offering higher rates of return and opportunities to convert undeveloped acreage to acreage held by production. These decreases were partially offset by an increase of 1,307 MBbls in crude oil production from our STACK properties due to additional wells being completed and producing as a result of a shift in our drilling and completion activities to high rate-of-return opportunities in that area.

The 19% increase in natural gas production in 2016 compared to 2015 was driven by increased production from our properties in the STACK and SCOOP plays due to additional wells being completed and producing subsequent to December 31, 2015. Natural gas production in STACK for 2016 increased 17,279 MMcf, or 161%, and SCOOP production increased 10,345 MMcf, or 11%, over the prior year. Additionally, North Dakota Bakken natural gas production for 2016 increased 3,107 MMcf, or 7%, due to an increase in gas capture from non-operated properties and resulting increase in volumes produced and delivered to market. These increases were partially offset by decreases in production from various areas in our North and South regions primarily due to natural declines in production.

The increase in natural gas production as a percentage of our total production from 34% in 2015 to 41% in 2016 primarily resulted from significant increases in STACK and SCOOP production due to a shift in our well completion activities away from the Bakken to higher rate-of-return areas in Oklahoma. Certain areas in STACK and SCOOP produce a higher concentration of natural gas compared to oil-weighted properties in the Bakken.

Revenues

Crude oil and natural gas sales. Crude oil and natural gas sales for 2016 were $2.03 billion, a 21% decrease from sales of $2.55 billion for 2015 due to decreases in commodity prices and total sales volumes.

Our crude oil sales prices averaged $35.51 per barrel for 2016, a decrease of 12% compared to $40.50 for 2015 due to lower market prices. The differential between NYMEX WTI calendar month crude oil prices and our realized crude oil prices averaged $7.33 per barrel for 2016 compared to $8.33 for 2015. The improved differential was due to increased use of pipeline transportation to move our North region crude oil to market with less dependence on more costly rail transportation, along with significant growth in our South region production which typically has lower transportation costs compared to the Bakken due to its relatively close proximity to regional refineries and the crude oil trading hub in Cushing, Oklahoma.

Our natural gas sales prices averaged $1.87 per Mcf for 2016, a 19% decrease compared to $2.31 per Mcf for 2015 due to lower market prices and the amendment of certain natural gas sales agreements in 2016. The amended contracts contributed to an increase in the discount between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices from $0.34 per Mcf for 2015 to $0.61 per Mcf for 2016.

Our total sales volumes for 2016 decreased 1,731 MBoe, or 2%, compared to 2015, reflecting natural production declines coupled with our reduced pace of drilling and completion activities during the year. For 2016, our crude oil sales volumes decreased 13% compared to 2015, while our natural gas sales volumes increased 19%, reflecting the shift in our well completion activities away from oil-weighted properties in the Bakken to areas in Oklahoma with higher concentrations of natural gas.

For the 2016 fourth quarter, crude oil and natural gas revenues totaled $591.8 million, representing a 17% increase from 2016 third quarter revenues of $505.9 million and a 7% increase from 2015 fourth quarter revenues of $551.4 million. Revenues for the 2016 fourth quarter were favorably impacted by increases in crude oil, natural gas and NGL market prices late in the year. Our crude oil sales prices averaged $42.23 per barrel in the 2016 fourth quarter compared to $37.66 for the 2016 third quarter and $34.23 for the 2015 fourth quarter. Our natural gas sales prices averaged $2.70 per Mcf in the 2016 fourth quarter compared to $2.02 for the 2016 third quarter and $2.07 for the 2015 fourth quarter.

Derivatives. Changes in natural gas prices during 2016 had an overall unfavorable impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $71.9 million for the year, representing $160.7 million

of non-cash losses partially offset by $88.8 million of cash gains.
Crude oil and natural gas service operations. Our crude oil and natural gas service operations consist primarily of revenues associated with water gathering, recycling, and disposal activities and the treatment and sale of lower quality reclaimed crude oil. Revenues associated with such activities decreased $11.4 million, or 31%, from $36.6 million for 2015 to $25.2 million for 2016 due to a reduction in handling and treatment activities resulting from a slow down in industry production activities.

Operating Costs and Expenses

Production expenses. Production expenses decreased $59.6 million, or 17%, from $348.9 million for 2015 to $289.3 million for 2016. Production expenses on a per-Boe basis decreased to $3.65 for 2016 compared to $4.30 for 2015. These decreases primarily resulted from reduced service costs being realized in response to depressed commodity prices, increased availability and use of water gathering and recycling facilities over the prior year period, and a higher portion of our production coming from wells in Oklahoma which typically have lower operating costs compared to wells in the Bakken.

Production taxes. Production taxes decreased $58.2 million, or 29%, to $142.4 million in 2016 compared to $200.6 million in 2015 primarily due to lower crude oil and natural gas revenues resulting from decreases in commodity prices and total sales volumes over the prior year. Production taxes as a percentage of crude oil and natural gas revenues were 7.0% for 2016 compared to 7.8% for 2015, the decrease of which resulted from significant growth over the past year in our STACK and SCOOP operations and resulting increase in revenues coming from Oklahoma, which has lower production tax rates compared to North Dakota.

Exploration expenses. The following table shows the components of exploration expenses for the periods presented.

| | Year ended December 31, | |
|---|---|---|
| In thousands | 2016 | 2015 |
| Geological and geophysical costs | $12,106 | $11,032 |
| Exploratory dry hole costs | 4,866 | 8,381 |
| Exploration expenses | $16,972 | $19,413 |

Dry hole costs incurred in 2016 and 2015 primarily reflect costs associated with unsuccessful wells in non-core areas of our North region.

Depreciation, depletion, amortization and accretion. Total DD&A decreased $40.3 million, or 2%, to $1.71 billion for 2016 compared to $1.75 billion for 2015 primarily due to a 2% decrease in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

| | Year ended December 31, | |
|---|---|---|
| $/Boe | 2016 | 2015 |
| Crude oil and natural gas properties | $21.09 | $21.18 |
| Other equipment | 0.37 | 0.33 |
| Asset retirement obligation accretion | 0.08 | 0.06 |
| Depreciation, depletion, amortization and accretion | $21.54 | $21.57 |

Property impairments. Total property impairments decreased $164.8 million, or 41%, to $237.3 million for 2016 compared to $402.1 million for 2015. Proved property impairments totaled $2.9 million for 2016 compared to $138.9 million for 2015. This decrease resulted from differences in the timing and severity of commodity price declines and resulting impact on fair value assessments and impairments between periods. The prolonged decrease in commodity prices in 2015 triggered significant impairments of proved properties throughout 2015. As a result of previously recognized impairments and DD&A, our proved properties were carried at values that, when compared to estimated future net cash flows, required minimal impairment during 2016.

Impairments of non-producing properties decreased $28.8 million, or 11%, in 2016 to $234.4 million, of which $34.6 million was recognized in the fourth quarter. The decrease was due to a lower balance of unamortized leasehold costs in 2016 due to property dispositions and reduced land capital expenditures, along with changes in the timing and magnitude of amortization of undeveloped leasehold costs between periods resulting from changes in the Company's estimates of undeveloped properties not expected to be developed before lease expiration.

General and administrative expenses. Total G&A expenses decreased $20.2 million, or 11%, to $169.6 million in 2016 from $189.8 million in 2015. Total G&A expenses include non-cash charges for equity compensation of $48.1 million and $51.8 million for 2016 and 2015, respectively. G&A expenses other than equity compensation included in the total G&A expense figure above totaled $121.5 million for 2016, a decrease of $16.5 million, or 12%, compared to $138.0 million for 2015.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

| $/Boe | Year ended December 31, 2016 | 2015 |
|---|---|---|
| General and administrative expenses | $1.53 | $1.70 |
| Non-cash equity compensation | 0.61 | 0.64 |
| Total general and administrative expenses | $2.14 | $2.34 |

The decrease in G&A expenses other than equity compensation was primarily due to a reduction in employee related costs and other efforts to reduce spending in response to depressed commodity prices. The decrease in equity compensation expense was primarily due to an increase in the estimated rate of forfeitures of unvested restricted stock based on historical experience, which resulted in lower recognition of expense in 2016.

Interest expense. Interest expense increased $7.5 million, or 2%, to $320.6 million in 2016 from $313.1 million in 2015 due to
higher borrowing costs incurred on our credit facility and three-year term loan resulting from downgrades of our credit rating in February 2016 along with an increase in our weighted average outstanding long-term debt resulting from fluctuations in the level of outstanding borrowings between years. Our weighted average outstanding long-term debt balance for 2016 was approximately $7.1 billion compared to $6.9 billion or 2015.

Income Taxes. We recorded an income tax benefit for the year ended December 31, 2016 of $232.8 million compared to a benefit of $181.4 million for 2015, resulting in effective tax rates of approximately 37% and 34%, respectively, after taking into account permanent taxable differences and valuation allowances. For 2016 and 2015, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax losses generated by our operations in the United States and 25% of pre-tax losses generated by our operations in Canada. Our 2015 consolidated effective tax rate was reduced by a $13.5 million valuation allowance recognized against deferred tax assets arising from $52.9 million of operating loss carryforwards generated by our Canadian subsidiary in 2015 for which we do not believe we will realize a benefit.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our revolving credit facility and the issuance of debt securities. Additionally, in recent years non-strategic asset dispositions have provided a source of cash flow for use in reducing debt and enhancing liquidity. We intend to continue reducing our long-term debt using available cash flows from operations and/or proceeds from additional potential sales of non-strategic assets or through joint development arrangements; however, no assurance can be given that such transactions will occur.

At December 31, 2017, we had $43.9 million of cash and cash equivalents and approximately $2.56 billion of borrowing availability on our revolving credit facility after considering outstanding borrowings of $188 million and letters of credit. At January 31, 2018, outstanding borrowings decreased to $93 million, leaving approximately $2.65 billion of borrowing availability on our credit facility at that date.

Based on our 2018 capital expenditure budget, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our revolving credit facility and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to the various agreements subsequently described under the heading Contractual Obligations and in Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies, recognizing we may be required to meet such commitments even if our business plan assumptions were to change. We monitor our capital spending closely based on actual and projected cash flows and have the ability to reduce spending or dispose of assets to preserve liquidity and financial flexibility if needed to fund our operations.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities totaled $2.08 billion and $1.13 billion for the years ended December 31, 2017 and 2016, respectively. The increase in operating cash flows was primarily due to an increase in crude oil and natural gas revenues driven by higher realized commodity prices and total sales volumes in 2017 coupled with lower interest expenses, the effects of which were partially offset by increases in production expenses, production taxes, and general and administrative expenses and a decrease in cash gains on matured natural gas derivatives.

Crude oil prices showed signs of improvement in late 2017 and early 2018 and through February 16, 2018 are higher than average market prices for full year 2017. If crude oil prices remain at current levels, we expect our 2018 operating cash flows will be higher than 2017 levels, the extent of which is uncertain due to the unpredictable nature of commodity prices.

Cash flows used in investing activities

During the years ended December 31, 2017 and 2016, we had cash flows used in investing activities of $1,808.8 million and $533.0 million, respectively. These totals include cash capital expenditures of $1,953.2 million and $1,164.5 million, respectively, inclusive of exploration and development drilling, property acquisitions, and dry hole costs. Property acquisitions totaled $40.0 million and $35.9 million for the years ended December 31, 2017 and 2016, respectively. The increase in capital spending was driven by an increase in our capital budget and related drilling and completion activities in 2017.

The use of cash for capital expenditures in 2017 and 2016 was partially offset by proceeds received from asset dispositions, which totaled $144.4 million and $631.5 million for the years ended December 31, 2017 and 2016, respectively. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 14. Property Dispositions for a discussion of notable dispositions.

For 2018, we currently expect our cash flows used in investing activities, exclusive of any proceeds from asset sales or joint development arrangements, will be higher than 2017 levels due to our planned increase in drilling and completion activity for 2018 in response to the improvement in crude oil prices in late 2017 and early 2018. Our capital expenditures for 2018 are budgeted to be $2.3 billion.

Cash flows from financing activities

Net cash used in financing activities for the year ended December 31, 2017 totaled $243.0 million, primarily resulting from a reduction in total outstanding debt using available cash flows from operations and proceeds from asset dispositions. The $990 million of net proceeds received from our December 2017 issuance of 2028 Notes were used to repay in full and terminate our $500 million term loan and to repay a portion of the borrowings outstanding under our revolving credit facility, thereby resulting in no significant net change in cash flows from financing activities related to these activities.

Net cash used in financing activities for the year ended December 31, 2016 totaled $587.8 million, primarily resulting from cash from asset sales being used to fund the November 2016 redemptions of our $200 million of 7.375% Senior Notes due 2020 and $400 million of 7.125% Senior Notes due 2021.

Future Sources of Financing

Although we cannot provide any assurance, we believe funds from operating cash flows, our remaining cash balance and availability under our revolving credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments for at least the next 12 months.

Our 2018 capital expenditures budget has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility or proceeds from asset sales or joint development arrangements.

If cash flows are materially impacted by declines in commodity prices, we have the ability to reduce our capital expenditures or utilize the availability of our revolving credit facility if needed to fund our operations. We may choose to access the capital markets for additional financing or capital to take advantage of business opportunities that may arise. Further, we may sell additional assets or enter into strategic joint development arrangements in order to obtain funding for our operations and capital program if such transactions can be executed on satisfactory terms.

We currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. We intend to fund future capital expenditures primarily through cash flows from operations and through borrowings under our revolving credit facility, but we may also issue debt or equity securities, sell additional assets, or enter into joint development arrangements. The issuance of additional debt requires a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Revolving credit facility

Currently we have an unsecured credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $2.75 billion. The commitments are from a syndicate of 17 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment.

As of January 31, 2018, we had approximately $2.65 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. Credit facility borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness.

The commitments under our revolving credit facility are not dependent on a borrowing base calculation subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, downgrades or other negative rating actions with respect to our credit rating would not trigger a reduction in our current credit facility commitments, nor would such actions trigger a security requirement or change in covenants. The weighted-average interest rate on our credit facility borrowings was 3.19% at December 31, 2017 and we incur commitment fees of 0.30% per annum on the daily average amount of unused borrowing availability.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, or merge, consolidate or sell all or substantially all of our assets. Our credit facility also contains a requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity plus, to the extent resulting in a reduction of total shareholders' equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014.

We were in compliance with our revolving credit facility covenants at December 31, 2017 and expect to maintain compliance for at least the next 12 months. At December 31, 2017, our consolidated net debt to total capitalization ratio, as defined in our revolving credit facility as amended, was 0.51 to 1.00. We do not believe the revolving credit facility covenants are reasonably likely to limit our ability to undertake additional debt financing to a material extent if needed to support our business. At December 31, 2017, our total debt would have needed to independently increase by approximately $5.2 billion above the existing level at that date (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders' equity would have needed to independently decrease by approximately $2.8 billion (excluding the after-tax impact of any non-cash impairment charges) below the existing level at December 31, 2017 to reach the maximum covenant ratio. These independent point-in-time sensitivities do not take into account other factors that could arise to mitigate the impact of changes in debt and equity on our consolidated net debt to total capitalization ratio, such as disposing of assets or exploring alternative sources of capitalization.

Joint development agreement funding

In September 2014, we entered into an agreement with a U.S. subsidiary of SK E&S Co. Ltd ("SK") of South Korea to jointly develop a portion of the Company's STACK properties. Pursuant to the agreement SK will fund, or carry, 50% of our drilling and completion costs attributable to an area of mutual interest in the STACK play until approximately $270 million has been expended by SK on our behalf. As of December 31, 2017, approximately $101 million of the carry had yet to be realized and is expected to be realized through mid-2019.

Future Capital Requirements

Senior notes

Our debt includes outstanding senior note obligations totaling $6.2 billion at December 31, 2017. We have no near-term senior note maturities, with our earliest scheduled senior note maturity being our $2.0 billion of 2022 Notes due in September 2022. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. For further information on the face values, maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to Part II, Item 8. Notes to Consolidated Financial Statements—Note 7. Long-Term Debt.

We were in compliance with our senior note covenants at December 31, 2017 and expect to maintain compliance for at least the next 12 months. We do not believe the senior note covenants will materially limit our ability to undertake additional debt financing. Downgrades or other negative rating actions with respect to the credit ratings assigned to our senior unsecured debt would not trigger additional senior note covenants.

Three of our subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. Our other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes as of December 31, 2017.

Capital expenditures

We evaluate opportunities to purchase or sell crude oil and natural gas properties and expect to participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas. Acquisition expenditures are not budgeted.

For the year ended December 31, 2017, we invested approximately $2.0 billion in our capital program, excluding $40.0 million of unbudgeted acquisitions, including $79.2 million of capital costs associated with increased accruals for capital expenditures, and including $2.8 million of seismic costs. Our capital expenditures budget for 2017 was $1.95 billion. Our 2017 capital expenditures were allocated as follows by quarter:

| In millions | 1Q 2017 | 2Q 2017 | 3Q 2017 | 4Q 2017 | Total 2017 |
|---|---|---|---|---|---|
| Exploration and development drilling | $329.8 | $471.0 | $444.7 | $442.2 | $1,687.7 |
| Land costs | 68.8 | 49.8 | 47.7 | 23.0 | 189.3 |
| Capital facilities, workovers and other corporate assets | 27.4 | 29.3 | 28.2 | 30.5 | 115.4 |
| Seismic | 1.0 | 1.8 | — | — | 2.8 |
| Capital expenditures, excluding acquisitions | $427.0 | $551.9 | $520.6 | $495.7 | $1,995.2 |
| Acquisitions of producing properties | 0.1 | 0.7 | 2.7 | 4.9 | 8.4 |
| Acquisitions of non-producing properties | 13.3 | 5.1 | 6.8 | 6.4 | 31.6 |
| Total acquisitions | 13.4 | 5.8 | 9.5 | 11.3 | 40.0 |
| Total capital expenditures | $440.4 | $557.7 | $530.1 | $507.0 | $2,035.2 |

Our capital expenditures budget for 2018 is $2.3 billion excluding acquisitions, which is expected to be allocated as follows:

| In millions | Amount |
|---|---|
| Exploration and development drilling | $ 1,988 |
| Land costs | 132 |
| Capital facilities, workovers and other corporate assets | 168 |
| Seismic | 12 |
| Total 2018 capital budget, excluding acquisitions | $ 2,300 |

Our drilling and completion activities and the actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, access to capital, available cash flows, unbudgeted acquisitions, actual drilling and completion results, the availability of drilling and completion rigs and other services and equipment, the availability of transportation and processing capacity, changes in commodity prices, and regulatory, technological and competitive developments. We monitor our capital spending closely based on actual and projected cash flows and may scale back our spending should commodity prices decrease from current levels. Conversely, an increase in commodity prices from current levels could result in increased capital expenditures. We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at competitive terms.

Contractual Obligations

The following table presents our contractual obligations and commitments as of December 31, 2017:

| | Payments due by period | | | | |
|---|---|---|---|---|---|
| In thousands | Total | Less than 1 year (2018) | Years 2 and 3 (2019-2020) | Years 4 and 5 (2021-2022) | More than 5 years |
| Arising from arrangements on the balance sheet: | | | | | |
| Revolving credit facility borrowings | $188,000 | $ — | $ 188,000 | $ — | $— |
| Senior Notes (1) | 6,200,000 | — | — | 2,000,000 | 4,200,000 |
| Note payable (2) | 10,021 | 2,286 | 4,795 | 2,940 | — |
| Interest payments (3) | 2,476,202 | 270,535 | 569,683 | 567,159 | 1,068,825 |
| Asset retirement obligations (4) | 114,406 | 2,612 | 3,486 | — | 108,308 |
| Arising from arrangements not on balance sheet: (5) | | | | | |
| Operating leases and other (6) | 26,956 | 11,867 | 6,581 | 1,300 | 7,208 |
| Drilling rig commitments (7) | 103,595 | 72,924 | 30,671 | — | — |

| | | | | | |
|---|---|---|---|---|---|
| Transportation and processing commitments (8) | 1,429,511 | 196,714 | 401,656 | 333,988 | 497,153 |
| Total contractual obligations | $10,548,691 | $ 556,938 | $1,204,872 | $2,905,387 | $5,881,494 |

(1) Amounts represent scheduled maturities of our senior note obligations at December 31, 2017 and do not reflect any discount or premium at which the senior notes were issued or any debt issuance costs. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 7. Long-Term Debt for a description of our senior notes.

(2) Represents future principal payments on a 10-year amortizing note payable secured by the Company's corporate office building in Oklahoma City, Oklahoma and does not reflect any debt issuance costs. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022.

(3) Interest payments include scheduled cash interest payments on the senior notes and note payable as well as estimated interest payments on our revolving credit facility borrowings outstanding at December 31, 2017 and assumes the actual weighted average interest rate on our credit facility borrowings of 3.19% at December 31, 2017 continues through the maturity date of the arrangement.

(4) Amounts represent estimated discounted costs for future dismantlement and abandonment of our crude oil and natural gas properties. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for additional discussion of our asset retirement obligations.

(5) The commitment amounts included in this section primarily represent costs associated with wells operated by the Company. A portion of these costs will be borne by other interest owners. Due to variations in well ownership, our net share of these costs cannot be determined with certainty.

(6) Amounts primarily represent commitments for electric infrastructure, land and road use, office buildings and equipment, communication towers, field equipment, sponsorship agreements, and purchase obligations mainly related to software services.

(7) Amounts represent commitments under drilling rig contracts with various terms extending to February 2020 to ensure rig availability in our key operating areas.

(8) We have entered into transportation and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities. These commitments require us to pay per-unit transportation or processing charges regardless of the amount of capacity used. We are not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies for additional discussion.

If the litigation settlement discussed in Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies is approved by the court, we will make payments and incur costs associated with the settlement of approximately $59.6 million. The timing of payments of our obligations under the settlement is uncertain and have not been reflected in the contractual obligations table above.

Derivative Instruments

We may utilize derivative instruments to economically hedge against the variability in cash flows associated with future sales of our production. While the use of derivative instruments limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 5. Derivative Instruments for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts as of December 31, 2017, and the estimated fair value of our contracts as of that date.

Between January 1, 2018 and February 16, 2018 we entered into additional natural gas derivative instruments as summarized below, representing the majority of our forecasted 2018 natural gas production. The hedged volumes reflected below represent an aggregation of multiple contracts that are generally expected to be realized ratably over the indicated period. These derivative instruments will be settled based upon reported NYMEX Henry Hub settlement prices.

| Period and Type of Contract | MMBtus | Swaps Weighted Average Price |
|---|---|---|
| February 2018 - December 2018 | | |
| Swaps - Henry Hub | 193,720,000 | $ 2.88 |

Critical Accounting Policies and Estimates

Our consolidated financial statements and related footnotes contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, and the disclosure and estimation of contingent assets and liabilities. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used.

In management's opinion, the most significant reporting areas impacted by management's judgments and estimates are crude oil and natural gas reserve estimations, revenue recognition, the choice of accounting method for crude oil and natural gas activities and derivatives, impairment of assets, income taxes and contingent liabilities. These areas are discussed below. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters and are believed to be reasonable under the circumstances. We evaluate our estimates and assumptions on a regular basis. Actual results could differ from the estimates as additional information becomes known.

Crude Oil and Natural Gas Reserves Estimation and Standardized Measure of Future Cash Flows

Our external independent reserve engineers, Ryder Scott, and internal technical staff prepare the estimates of our crude oil and natural gas reserves and associated future net cash flows. Even though Ryder Scott and our internal technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Estimates of reserves and their values, future production rates, and future costs and expenses are inherently uncertain for various reasons, including many factors beyond the Company's control. Reserve estimates are updated by us at least semi-annually and take into account recent production levels and other technical information about each of our properties.

Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates may differ significantly from the quantities of crude oil and natural gas ultimately recovered. For the years ended December 31, 2017, 2016, and 2015, our proved reserves were revised downward from prior years' reports by approximately 82 MMBoe, 110 MMBoe, and 297 MMBoe, respectively. We cannot predict the amounts or timing of future reserve revisions.

Estimates of proved reserves are key components of the Company's most significant financial estimates including the computation of depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense would increase, reducing net income. Conversely, if proved reserves are revised upward, the rate at which we record DD&A expense would decrease. Future revisions of reserves may be material and could significantly alter future depreciation, depletion, and amortization expense and may result in material impairments of assets.

At December 31, 2017, our proved reserves totaled 1,331 MMBoe as determined using 12-month average first-day-of-the-month prices of $51.34 per barrel for crude oil and $2.98 per MMBtu for natural gas. Actual future prices may be materially higher or lower than those used in our year-end estimates. NYMEX WTI crude oil and Henry Hub natural gas first-day-of-the-month commodity prices for January 1, 2018 and February 1, 2018 averaged $63.11 per barrel and $3.40 per MMBtu, respectively.

Holding all other factors constant, if crude oil prices used in our year-end reserve estimates were increased to $65 per barrel our proved reserves at December 31, 2017 could increase by approximately 24 MMBoe, or 2%, representing a 3% increase in proved developed producing reserves averaged with a 1% increase in PUD reserves. If the increase in proved reserves under this price sensitivity existed throughout 2017, our DD&A expense for 2017 would have decreased by an estimated 3%.

Holding all other factors constant, if natural gas prices used in our year-end reserve estimates were increased to $4.00 per MMBtu our proved reserves at December 31, 2017 could increase by approximately 8 MMBoe, or 1%, which we estimate would result in an approximate 1% decrease in DD&A expense for 2017 assuming the increase in proved reserves under this price sensitivity existed throughout the year.

Our DD&A calculations for oil and gas properties are performed on a field basis and revisions to proved reserves will not necessarily be applied ratably across all fields and may not be applied to some fields at all. Further, reserve revisions in significant fields may individually affect our DD&A rate. As a result, the impact on DD&A expense from revisions in reserves cannot be predicted with certainty and may result in changes in expense that are greater or less than the underlying changes in reserves.

See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve, Standardized Measure, and PV-10 Sensitivities for additional proved reserve sensitivities under certain increasing and decreasing commodity price scenarios for crude oil and natural gas.

Revenue Recognition

We derive substantially all of our revenues from the sale of crude oil and natural gas. Crude oil and natural gas revenues are recognized in the month the product is delivered to the purchaser and title transfers. We generally receive payment from one to three months after the sale has occurred. At the end of each month, to record revenue we estimate the amount of production delivered and sold to purchasers and the prices at which they were sold. Variances between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received and are reflected in our financial statements as crude oil and natural gas sales. These variances have historically not been material.

New accounting rules governing the recognition and presentation of revenues went into effect on January 1, 2018. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies–New accounting pronouncements not yet adopted at December 31, 2017–Revenue recognition and presentation for discussion of the expected impact of the new rules on our future financial statements.

Successful Efforts Method of Accounting

Our business is subject to accounting rules that are unique to the crude oil and natural gas industry. Two generally accepted methods of accounting for oil and gas activities are available—the successful efforts method and the full cost method. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. We use the successful efforts method of accounting for our oil and gas properties. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for further discussion of the accounting policies applicable to the successful efforts method of accounting.

Derivative Activities

We may utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of future crude oil and natural gas production and forecasted purchases of diesel fuel for use in drilling activities. We have elected not to designate any of our price risk management activities as cash flow hedges. As a result, we mark our derivative instruments to fair value and recognize the changes in fair value in current earnings.

In determining the amounts to be recorded for our open derivative contracts, we are required to estimate the fair value of the derivatives. We use an independent third party to provide our derivative valuations. The third party’s valuation models for derivative contracts are industry-standard models that consider various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value calculations for collars requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the derivative agreements and the resulting estimated future cash inflows or outflows over the lives of the derivatives are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates. See Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk for a discussion of the sensitivity of natural gas derivative fair value calculations to changes in forward natural gas prices.

We validate our derivative valuations through management review and by comparison to our counterparties’ valuations for reasonableness. Differences between our fair value calculations and counterparty valuations have historically not been material.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk-adjusted proved reserves. Risk-adjusted probable and possible reserves may be taken into consideration when determining estimated future net cash flows and fair value when such reserves exist and are economically recoverable.

Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis. If the carrying amount of a field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value using a discounted cash flow model. For producing properties, the impairment evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for crude oil and natural gas, future costs to produce those products, estimates of future crude oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions to crude oil and natural gas reserves. Estimates of anticipated sales prices and recoverable reserves are highly judgmental and are subject to material revision in future periods.

Impairment provisions for producing properties totaled $82.3 million for 2017. Commodity price assumptions used for the year-end December 31, 2017 impairment calculations were based on publicly available average annual forward commodity strip prices through year-end 2022 and were then escalated at 3% per year thereafter. Holding all other factors constant, as forward commodity prices decrease, our probability for recognizing producing property impairments may increase, or the magnitude of impairments to be recognized may increase. Conversely, as forward commodity prices increase, our probability for recognizing producing property impairments may decrease, or the magnitude of impairments to be recognized may decrease or be eliminated. As of December 31, 2017, the publicly available forward commodity strip prices for the year 2022 used in our fourth quarter impairment calculations averaged $51.65 per barrel for crude oil and $2.89 per Mcf for natural gas. If forward commodity prices materially decrease from current levels for an extended period, additional impairments of producing properties may be recognized in the future. Because of the uncertainty inherent in the numerous factors utilized in determining the fair value of producing properties, we cannot predict the timing and amount of future impairment charges, if any.

Impairment losses for non-producing properties, which primarily consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves, are recognized by amortizing the portion of the properties’ costs which management estimates will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period. The impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms, and potential shifts in business strategy employed by management. The estimated timing and rate of successful drilling is highly judgmental and is subject to material revision in future periods as better information becomes available.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain deferred tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2017, we believe all deferred tax assets, net of valuation allowances, reflected in our consolidated balance sheets will ultimately be utilized. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly related to prevailing crude oil and natural gas prices). If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision could increase in the period it is determined that it is more likely than not that a deferred tax asset will not be utilized.

Our effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax-paying companies. Our effective tax rate is affected by permanent taxable differences, valuation allowances, and changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state. Due to the size of our gross deferred tax balances, a small change in our estimated future tax rate can have a material effect on current period earnings.

Contingent Liabilities
A provision for legal, environmental and other contingencies is charged to expense when a loss is probable and the loss or range of loss can be reasonably estimated. Determining when liabilities and expenses should be recorded for these contingencies and the appropriate amounts of accruals is subject to an estimation process that requires subjective judgment of management. In certain cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations which can be interpreted differently by regulators and/or courts of law, the experience of the Company and other companies dealing with similar matters, and management's decision on how it intends to respond to a particular matter; for example, a decision to contest it vigorously or a decision to seek a negotiated settlement. Actual losses can differ from estimates for various reasons, including differing interpretations of laws and opinions and assessments on the amount of damages. We closely monitor known and potential legal, environmental and other contingencies and make our best estimate of when or if to record liabilities and losses for matters based on available information.
Off-Balance Sheet Arrangements
Currently, we do not have any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resources.
New Accounting Pronouncements
See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for a discussion of the impact upon adoption of new accounting pronouncements in 2017 along with a discussion of accounting pronouncements not yet adopted.
Legislative and Regulatory Developments
The crude oil and natural gas industry in the United States is subject to various types of regulation at the federal, state and local levels. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry for a discussion of significant laws and regulations that have been enacted or are currently being considered by regulatory bodies that may affect us in the areas in which we operate.
Tax Reform Legislation
On December 22, 2017, the Tax Reform Act was signed into law, which represents the most significant tax policy change in the United States since 1986. Below is a summary of key changes included in the new law that are most relevant to our business. Changes arising from the Tax Reform Act, which are subject to a number of important qualifications and exceptions not included in the summary below, generally become effective for tax years beginning after December 31, 2017. The following discussion should be read in conjunction with Part II, Item 8. Notes to Consolidated Financial Statements—Note 8. Income Taxes.
Reduction in corporate tax rate—the Tax Reform Act reduces the corporate tax rate from 35% to 21%, effective for tax years beginning after December 31, 2017. In recent years, we have provided for income taxes at a combined federal and state tax rate of 38% of pre-tax income and losses generated by our operations in the United States, representing 35% for federal income taxes and 3% for state income taxes. For 2018, under the new tax law we expect to provide for income taxes at a combined federal and state tax rate of approximately 24%. The new lower federal tax rate is expected to have a significant favorable impact on our U.S. GAAP net income in future periods.
Repeal of alternative minimum tax—the Tax Reform Act repeals the corporate alternative minimum tax ("AMT"), effective for tax years beginning after December 31, 2017. Further, the new law allows an entity to claim portions of any unused AMT credits over the next four years to offset its regular tax liability. An entity with unused AMT credits as of December 31, 2017 can first use those credits to offset its regular tax for 2017, and can then claim up to 50% of the remaining AMT credits in 2018, 2019, and 2020, with all remaining AMT credits refundable in 2021. This law change is expected to have a favorable impact on the Company relative to previous AMT rules. Our unused AMT credits totaled $7.8 million at December 31, 2017, which we believe are realizable and will be pursued for refund.
Net operating loss deduction limitation—the Tax Reform Act limits the amount entities are able to deduct for federal net operating loss ("NOL") carryforwards generated in tax years beginning after December 31, 2017 to 80% of taxable income for a respective year. The law also generally repeals an entity's ability to carry back future NOLs to prior periods. These adverse rule changes are mitigated by a law change that now allows any NOLs generated in taxable years beginning after December 31, 2017 to be carried forward indefinitely. NOLs arising before January 1, 2018 may

still be carried back two years and are subject to their existing carryforward expiration periods. These new law changes, when considered in the aggregate, are not expected to have a significant adverse impact on our ability to fully utilize current and future federal NOL carryforwards.

As of December 31, 2017, we had federal NOL carryforwards of $2.39 billion which begin expiring in 2033. Deferred tax assets reflected in our consolidated balance sheet related to these NOL carryforwards totaled $604.4 million at December 31, 2017. In response to the tax law changes, we reassessed the realizability of these deferred tax assets, taking into consideration how the new laws impact future taxable income, if any, that is expected to be offset by our NOLs. We believe our available NOLs at December 31, 2017 will ultimately be utilized prior to expiration and, as a result, no valuation allowance on our NOL deferred tax assets is necessary as of December 31, 2017.
Interest expense deduction limitation—the Tax Reform Act limits the deduction for business interest expense to 30% of adjusted taxable income for tax years beginning after December 31, 2017. Before January 1, 2022, the calculation of adjusted taxable income is similar to taxable earnings before interest, taxes, depreciation, and amortization (EBITDA). After January 1, 2022, that calculation is equivalent to taxable earnings before interest and taxes (EBIT). These adverse changes are mitigated by a law change that now allows any disallowed interest expense to be carried forward indefinitely. Based on our current tax planning strategies, these changes are not expected to have a significant adverse impact on our ability to deduct interest expenses for at least the next five years.
Acceleration of bonus depreciation—under the Tax Reform Act, entities are able to claim bonus depreciation to accelerate the expensing of the cost of certain qualified property acquired and placed into service after September 27, 2017 and before January 1, 2023. For the first five-year period (2018 through 2022), companies can deduct 100% of the cost of qualified property compared to a 50% allowance under previous law. During the period starting in 2023, the additional bonus depreciation is gradually phased out by 20% each year through 2027. This law change is expected to have a favorable impact on the Company as it has the potential to reduce or eliminate future taxable income or increase NOLs for utilization in future periods.
Executive compensation deduction limitation—for tax years beginning after December 31, 2017, the Tax Reform Act limits an entity's ability to deduct compensation in excess of $1 million for certain employees regardless of the character of those payments. Further, the new law expands the number of individuals whose compensation is subject to the $1 million limitation and expands the types of equity awards to be included in the calculations. These changes will limit our ability to deduct future executive compensation expenses, the impact of which is uncertain but is not expected to be significant to our business.
Impact on foreign operations—the Tax Reform Act introduces new rules that significantly change fundamental aspects of the taxation of foreign earnings of U.S. entities. Notably, the new law subjects unrepatriated foreign earnings to a mandatory one-time transition tax on post-1986 earnings at a rate of 15.5% for foreign earnings held in the form of cash and certain liquid assets and at a rate of 8% for all other foreign earnings. Our foreign operations are immaterial and have not generated taxable income historically and are not expected to generate significant taxable income in the future. Additionally, we have no significant cash or liquid assets held in foreign countries. Accordingly, the foreign tax law changes in the Tax Reform Act are not expected to have a significant impact on our business.
In addition to the changes described above, the Tax Reform Act includes a multitude of other provisions that broaden the tax base and eliminate or reduce other deductions, exclusions, and credits, none of which are expected to individually have a significant impact on our business.
The Tax Reform Act is generally expected to have an overall favorable impact on our business primarily due to expected benefits from the reduced corporate tax rate. The new laws are not expected to adversely impact our liquidity or the amount of cash payments we make for income taxes for at least the next five years.

Inflation

Certain drilling and completion costs and costs of oilfield services, equipment, and materials decreased in recent years as service providers reduced their costs in response to reduced demand arising from low crude oil prices. However, inflationary pressures returned in 2017 and are expected to continue in 2018 in conjunction with the stabilization and improvement in crude oil prices in recent months. As a result of the low commodity price environment in recent years, the number of providers of services, equipment, and materials decreased in the regions where we operate. If commodity prices show signs of sustained recovery and industry drilling and completion activities increase, we may face shortages of service providers, equipment, and materials. Such shortages could result in increased competition which may lead to further increases in costs.

Non-GAAP Financial Measures

PV-10

Our PV-10 value, a non-GAAP financial measure, is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2017, our PV-10 totaled approximately $11.83 billion. The standardized measure of our discounted future net cash flows was approximately $10.47 billion at December 31, 2017, representing a $1.36 billion difference from PV-10 due to the effect of deducting estimated future income taxes in arriving at Standardized Measure. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

General. We are exposed to a variety of market risks including commodity price risk, credit risk, and interest rate risk. We seek to address these risks through a program of risk management which may include the use of derivative instruments.

Commodity Price Risk. Our primary market risk exposure is in the prices we receive from sales of our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for crude oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the quarter ended December 31, 2017, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $613 million for each $10.00 per barrel change in crude oil prices and $260 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by market fluctuations in crude oil and natural gas prices, from time to time we may economically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps secure funds to be used for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize gain positions for the purpose of funding our capital program. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements. We have hedged the majority of our forecasted 2018 natural gas production. Our future crude oil production is currently unhedged and directly exposed to continued volatility in market prices, whether favorable or unfavorable.

Changes in natural gas prices during the year ended December 31, 2017 had an overall favorable impact on the fair value of our derivative instruments. For the year ended December 31, 2017, we recognized cash gains on natural gas derivatives of $29.6 million and non-cash mark-to-market gains on natural gas derivatives of $62.1 million.

The fair value of our natural gas derivative instruments at December 31, 2017 was a net asset of $2.6 million. An assumed increase in the forward prices used in the year-end valuation of our natural gas derivatives of $1.00 per MMBtu would change our natural gas derivative valuation to a net liability of approximately $2 million at December 31, 2017. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $7 million at December 31, 2017. Changes in the fair value of our natural gas derivatives from the above price sensitivities would produce a corresponding change in our total revenues.

See Part II, Item 8. Notes to Consolidated Financial Statements—Note 5. Derivative Instruments for further discussion of our hedging activities, including a summary of derivative contracts in place as of December 31, 2017.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, crude oil refining companies, and natural gas gathering and processing companies ($672 million in receivables at December 31, 2017); our joint interest and other receivables ($427 million at December 31, 2017); and counterparty credit risk associated with our derivative instrument receivables ($3 million at December 31, 2017).

We monitor our exposure to counterparties on crude oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's credit worthiness. We have not generally required our counterparties to provide collateral to secure crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

Joint interest receivables arise from billing the individuals and entities who own a partial interest in the wells we operate. These individuals and entities participate in our wells primarily based on their ownership in leases included in units on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to this credit risk we generally request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. This liability was $35 million at December 31, 2017, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We may have the right to place a lien on a co-owner's interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to any variable-rate borrowings we may have outstanding from time to time under our revolving credit facility. Such borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates.

We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives.

We had $93 million of variable rate borrowings outstanding on our revolving credit facility at January 31, 2018. The impact of a 0.25% increase in interest rates on this amount of debt would result in increased interest expense and reduced net income of approximately $0.2 million per year.

The following table presents our debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2017:

| In thousands | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Fixed rate debt: | | | | | | | |
| Senior Notes: | | | | | | | |
| Principal amount (1) | $— | $— | $— | $— | $2,000,000 | $4,200,000 | $6,200,000 |
| Weighted-average interest rate | — | — | — | — | 5.0 % | 4.4 % | 4.6 % |
| Note payable: | | | | | | | |
| Principal amount | $2,286 | $2,360 | $2,435 | $2,515 | $425 | $— | $10,021 |
| Interest rate | 3.1 % | 3.1 % | 3.1 % | 3.1 % | 3.1 % | — | 3.1 % |
| Variable rate debt: | | | | | | | |
| Revolving credit facility: | | | | | | | |
| Principal amount | $— | $188,000 | $— | $— | $— | $— | $188,000 |
| Weighted-average interest rate | — | 3.2 % | — | — | — | — | 3.2 % |

(1) Amounts do not reflect any discount or premium at which the senior notes were issued.

## Item 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 21, 2018 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2004.

Oklahoma City, Oklahoma
February 21, 2018

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

| In thousands, except par values and share data | December 31, 2017 | 2016 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $43,902 | $16,643 |
| Receivables: | | |
| Crude oil and natural gas sales | 671,665 | 404,750 |
| Affiliated parties | 63 | 99 |
| Joint interest and other, net | 426,585 | 364,850 |
| Derivative assets | 2,603 | 4,061 |
| Inventories | 97,406 | 111,987 |
| Prepaid expenses and other | 9,501 | 10,843 |
| Total current assets | 1,251,725 | 913,233 |
| Net property and equipment, based on successful efforts method of accounting | 12,933,789 | 12,881,227 |
| Other noncurrent assets | 14,137 | 17,316 |
| Total assets | $14,199,651 | $13,811,776 |
| | | |
| Liabilities and shareholders' equity | | |
| Current liabilities: | | |
| Accounts payable trade | $692,908 | $476,342 |
| Revenues and royalties payable | 374,831 | 217,425 |
| Payables to affiliated parties | 143 | 148 |
| Accrued liabilities and other | 260,074 | 176,770 |
| Derivative liabilities | — | 59,489 |
| Current portion of long-term debt | 2,286 | 2,219 |
| Total current liabilities | 1,330,242 | 932,393 |
| Long-term debt, net of current portion | 6,351,405 | 6,577,697 |
| Other noncurrent liabilities: | | |
| Deferred income tax liabilities, net | 1,259,558 | 1,890,305 |
| Asset retirement obligations, net of current portion | 111,794 | 94,436 |
| Other noncurrent liabilities | 15,449 | 14,949 |
| Total other noncurrent liabilities | 1,386,801 | 1,999,690 |
| Commitments and contingencies (Note 10) | | |
| Shareholders' equity: | | |
| Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding | — | — |
| Common stock, $0.01 par value; 1,000,000,000 shares authorized; 375,219,769 shares issued and outstanding at December 31, 2017; 374,492,357 shares issued and outstanding at December 31, 2016 | 3,752 | 3,745 |
| Additional paid-in capital | 1,409,326 | 1,375,290 |
| Accumulated other comprehensive income (loss) | 307 | (260) |
| Retained earnings | 3,717,818 | 2,923,221 |
| Total shareholders' equity | 5,131,203 | 4,301,996 |
| Total liabilities and shareholders' equity | $14,199,651 | $13,811,776 |

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)

| | Year Ended December 31, | | |
|---|---|---|---|
| In thousands, except per share data | 2017 | 2016 | 2015 |
| Revenues: | | | |
| Crude oil and natural gas sales | $2,982,966 | $2,026,958 | $2,551,131 |
| Crude oil and natural gas sales to affiliates | — | — | 1,400 |
| Gain (loss) on crude oil and natural gas derivatives, net | 91,647 | (71,859) | 91,085 |
| Crude oil and natural gas service operations | 46,215 | 25,174 | 36,551 |
| Total revenues | 3,120,828 | 1,980,273 | 2,680,167 |
| Operating costs and expenses: | | | |
| Production expenses | 324,214 | 289,289 | 347,243 |
| Production expenses to affiliates | — | — | 1,654 |
| Production taxes | 208,278 | 142,388 | 200,637 |
| Exploration expenses | 12,393 | 16,972 | 19,413 |
| Crude oil and natural gas service operations | 16,880 | 11,386 | 17,337 |
| Depreciation, depletion, amortization and accretion | 1,674,901 | 1,708,744 | 1,749,056 |
| Property impairments | 237,370 | 237,292 | 402,131 |
| General and administrative expenses | 191,706 | 169,580 | 189,846 |
| Litigation settlement | 59,600 | — | — |
| Net gain on sale of assets and other | (53,915) | (307,844) | (23,149) |
| Total operating costs and expenses | 2,671,427 | 2,267,807 | 2,904,168 |
| Income (loss) from operations | 449,401 | (287,534) | (224,001) |
| Other income (expense): | | | |
| Interest expense | (294,495) | (320,562) | (313,079) |
| Loss on extinguishment of debt | (554) | (26,055) | — |
| Other | 1,715 | 1,697 | 1,995 |
| | (293,334) | (344,920) | (311,084) |
| Income (loss) before income taxes | 156,067 | (632,454) | (535,085) |
| Benefit for income taxes | 633,380 | 232,775 | 181,417 |
| Net income (loss) | $789,447 | $(399,679) | $(353,668) |
| Basic net income (loss) per share | $2.13 | $(1.08) | $(0.96) |
| Diluted net income (loss) per share | $2.11 | $(1.08) | $(0.96) |
| Comprehensive income (loss): | | | |
| Net income (loss) | $789,447 | $(399,679) | $(353,668) |
| Other comprehensive income (loss), net of tax: | | | |
| Foreign currency translation adjustments | 567 | 3,094 | (2,969) |
| Total other comprehensive income (loss), net of tax | 567 | 3,094 | (2,969) |
| Comprehensive income (loss) | $790,014 | $(396,585) | $(356,637) |

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Shareholders' Equity

| In thousands, except share data | Shares outstanding | Common stock | Additional paid-in capital | Accumulated other comprehensive income (loss) | Retained earnings | Total shareholders' equity |
|---|---|---|---|---|---|---|
| Balance at December 31, 2014 | 372,005,502 | $ 3,720 | $ 1,287,941 | $ (385 ) | $ 3,676,568 | $ 4,967,844 |
| Net loss | — | — | — | — | (353,668 ) | (353,668 ) |
| Other comprehensive loss, net of tax | — | — | — | (2,969 ) | — | (2,969 ) |
| Stock-based compensation | — | — | 51,817 | — | — | 51,817 |
| Tax benefit from stock-based compensation | — | — | 13,177 | — | — | 13,177 |
| Restricted stock: | | | | | | |
| Granted | 1,462,534 | 15 | — | — | — | 15 |
| Repurchased and canceled | (172,786 ) | (2 ) | (7,311 ) | — | — | (7,313 ) |
| Forfeited | (336,170 ) | (3 ) | — | — | — | (3 ) |
| Balance at December 31, 2015 | 372,959,080 | $ 3,730 | $ 1,345,624 | $ (3,354 ) | $ 3,322,900 | $ 4,668,900 |
| Net loss | — | — | — | — | (399,679 ) | (399,679 ) |
| Other comprehensive income, net of tax | — | — | — | 3,094 | — | 3,094 |
| Stock-based compensation | — | — | 48,084 | — | — | 48,084 |
| Tax deficiency from stock-based compensation | — | — | (9,828 ) | — | — | (9,828 ) |
| Restricted stock: | | | | | | |
| Granted | 2,064,508 | 20 | — | — | — | 20 |
| Repurchased and canceled | (337,981 ) | (3 ) | (8,590 ) | — | — | (8,593 ) |
| Forfeited | (193,250 ) | (2 ) | — | — | — | (2 ) |
| Balance at December 31, 2016 | 374,492,357 | $ 3,745 | $ 1,375,290 | $ (260 ) | $ 2,923,221 | $ 4,301,996 |
| Cumulative effect adjustment from adoption of ASU 2016-09 (see Note 1) | — | — | — | — | 5,150 | 5,150 |
| Net income | — | — | — | — | 789,447 | 789,447 |
| Other comprehensive income, net of tax | — | — | — | 567 | — | 567 |
| Stock-based compensation | — | — | 45,854 | — | — | 45,854 |
| Restricted stock: | | | | | | |
| Granted | 1,585,870 | 16 | — | — | — | 16 |
| Repurchased and canceled | (259,729 ) | (3 ) | (11,818 ) | — | — | (11,821 ) |
| Forfeited | (598,729 ) | (6 ) | — | — | — | (6 ) |
| Balance at December 31, 2017 | 375,219,769 | $ 3,752 | $ 1,409,326 | $ 307 | $ 3,717,818 | $ 5,131,203 |

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

| In thousands | Year Ended December 31, 2017 | 2016 | 2015 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net income (loss) | $789,447 | $(399,679) | $(353,668) |
| Adjustments to reconcile net income (loss) to cash provided by operating activities: | | | |
| Depreciation, depletion, amortization and accretion | 1,670,838 | 1,709,567 | 1,746,454 |
| Property impairments | 237,370 | 237,292 | 402,131 |
| Non-cash (gain) loss on derivatives, net | (58,031) | 156,621 | (21,532) |
| Stock-based compensation | 45,868 | 48,098 | 51,834 |
| Tax benefit from US tax reform legislation | (713,655) | — | — |
| Provision (benefit) for deferred income taxes from operations | 88,056 | (209,836) | (181,441) |
| Tax deficiency (benefit) from stock-based compensation | — | 9,828 | (13,177) |
| Dry hole costs | 176 | 4,866 | 8,381 |
| Litigation settlement | 59,600 | — | — |
| Gain on sale of assets, net | (55,124) | (304,489) | (23,149) |
| Loss on extinguishment of debt | 554 | 26,055 | — |
| Other, net | 12,592 | 9,812 | 12,646 |
| Changes in assets and liabilities: | | | |
| Accounts receivable | (329,811) | (158,383) | 524,973 |
| Inventories | 14,517 | (17,836) | 7,997 |
| Other current assets | 1,038 | 968 | 65,493 |
| Accounts payable trade | 137,339 | (14,404) | (201,434) |
| Revenues and royalties payable | 158,982 | 30,455 | (85,754) |
| Accrued liabilities and other | 21,368 | (883) | (84,056) |
| Other noncurrent assets and liabilities | (2,018) | (2,133) | 1,403 |
| Net cash provided by operating activities | 2,079,106 | 1,125,919 | 1,857,101 |
| | | | |
| Cash flows from investing activities: | | | |
| Exploration and development | (1,931,942) | (1,154,131) | (3,042,747) |
| Purchase of producing crude oil and natural gas properties | (8,446) | (5,008) | (557) |
| Purchase of other property and equipment | (12,810) | (5,375) | (36,951) |
| Proceeds from sale of assets | 144,353 | 631,549 | 34,008 |
| Net cash used in investing activities | (1,808,845) | (532,965) | (3,046,247) |
| | | | |
| Cash flows from financing activities: | | | |
| Credit facility borrowings | 1,302,000 | 1,691,000 | 2,001,000 |
| Repayment of credit facility | (2,019,000) | (1,639,000) | (1,313,000) |
| Proceeds from issuance of Senior Notes | 990,000 | — | — |
| Redemption of Senior Notes | — | (600,000) | — |
| Premium on redemption of Senior Notes | — | (19,168) | — |
| Proceeds from other debt | — | — | 500,000 |
| Repayment of other debt | (502,214) | (2,144) | (2,078) |
| Debt issuance costs | (1,999) | (40) | (4,597) |
| Repurchase of restricted stock for tax withholdings | (11,821) | (8,593) | (7,313) |
| Tax (deficiency) benefit from stock-based compensation | — | (9,828) | 13,177 |
| Net cash (used in) provided by financing activities | (243,034) | (587,773) | 1,187,189 |

| | | | |
|---|---|---|---|
| Effect of exchange rate changes on cash | 32 | (1 ) | (10,961 ) |
| Net change in cash and cash equivalents | 27,259 | 5,180 | (12,918 ) |
| Cash and cash equivalents at beginning of period | 16,643 | 11,463 | 24,381 |
| Cash and cash equivalents at end of period | $43,902 | $16,643 | $11,463 |

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

Continental Resources, Inc. and Subsidiaries
Notes to Consolidated Financial Statements
Note 1. Organization and Summary of Significant Accounting Policies
Description of the Company

Continental Resources, Inc. (the “Company”) was originally formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company’s principal business is crude oil and natural gas exploration, development and production with properties primarily located in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi River and includes North Dakota Bakken, Montana Bakken, and the Red River units. The South region includes all properties south of Nebraska and west of the Mississippi River including various plays in the SCOOP (South Central Oklahoma Oil Province) and STACK (Sooner Trend Anadarko Canadian Kingfisher) areas of Oklahoma. The East region is primarily comprised of undeveloped leasehold acreage east of the Mississippi River with no significant drilling or production operations.

A substantial portion of the Company’s operations is located in the North region, with that region comprising approximately 59% of the Company’s crude oil and natural gas production and approximately 69% of its crude oil and natural gas revenues for the year ended December 31, 2017. The Company’s principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. As of December 31, 2017, approximately 50% of the Company’s estimated proved reserves were located in the North region. In recent years, the Company has significantly expanded its operations in the South region with its increased activity in the SCOOP and STACK plays. The South region comprised approximately 41% of the Company’s crude oil and natural gas production, 31% of its crude oil and natural gas revenues, and 50% of its estimated proved reserves as of and for the year ended December 31, 2017.

For the year ended December 31, 2017, crude oil accounted for approximately 57% of the Company’s total production and approximately 78% of its crude oil and natural gas revenues. Crude oil represents approximately 48% of the Company’s estimated proved reserves as of December 31, 2017.

Basis of presentation of consolidated financial statements

The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are 100% owned, after all significant intercompany accounts and transactions have been eliminated upon consolidation.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States (“U.S. GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results may differ from those estimates. The most significant estimates and assumptions impacting reported results are estimates of the Company’s crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties.

Revenue recognition

Crude oil and natural gas sales result from interests owned by the Company in crude oil and natural gas properties. Sales of crude oil and natural gas produced from crude oil and natural gas operations are recognized when the product is delivered to the purchaser and title transfers to the purchaser. Payment is generally received one to three months after the sale has occurred. The Company uses the sales method of accounting for natural gas imbalances in those circumstances where it has under-produced or over-produced its ownership percentage in a property. Under this method, a receivable or payable is recognized only to the extent an imbalance cannot be recouped from the reserves in the underlying properties. The Company’s aggregate imbalance positions at December 31, 2017 and 2016 were not material.

New accounting rules governing the recognition and presentation of revenues went into effect on January 1, 2018. See the subsequent section titled "New accounting pronouncements not yet adopted at December 31, 2017–Revenue recognition and presentation" for discussion of the expected impact of the new rules on the Company's future financial statements.

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Cash and cash equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The Company maintains its cash and cash equivalents in accounts that may not be federally insured. As of December 31, 2017, the Company had cash deposits in excess of federally insured amounts of approximately $42.5 million. The Company has not experienced any losses in such accounts and believes it is not exposed to significant credit risk in this area.

Accounts receivable

The Company operates exclusively in crude oil and natural gas exploration and production related activities. Receivables arising from crude oil and natural gas sales and joint interest receivables are generally unsecured. Accounts receivable are due within 30 days and are considered delinquent after 60 days. The Company determines its allowance for doubtful accounts by considering a number of factors, including the length of time accounts are past due, the Company's history of losses, and the customer or working interest owner's ability to pay. The Company writes off specific receivables when they become noncollectable and any payments subsequently received on those receivables are credited to the allowance for doubtful accounts. Write-offs of noncollectable receivables have historically not been material. The Company's allowance for doubtful accounts totaled $2.2 million and $3.0 million as of December 31, 2017 and 2016, respectively, which is included in "Receivables—Joint interest and other, net" on the consolidated balance sheets.

Concentration of credit risk

The Company is subject to credit risk resulting from the concentration of its crude oil and natural gas receivables with several significant purchasers. For the year ended December 31, 2017, sales to the Company's two largest purchasers accounted for approximately 11% and 11%, respectively, of the Company's total crude oil and natural gas sales. No other purchaser accounted for more than 10% of the Company's total crude oil and natural gas sales for 2017. The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers in various regions.

Inventories

Inventory is comprised of crude oil held in storage or as line fill in pipelines and tubular goods and equipment to be used in the Company's exploration and development activities. Crude oil inventories are valued at the lower of cost or market primarily using the first-in, first-out inventory method. Tubular goods and equipment are valued primarily using a weighted average cost method applied to specific classes of inventory items.

The components of inventory as of December 31, 2017 and 2016 consisted of the following:

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Tubular goods and equipment | $14,946 | $15,243 |
| Crude oil | 82,460 | 96,744 |
| Total | $97,406 | $111,987 |

Crude oil and natural gas properties

The Company uses the successful efforts method of accounting for crude oil and natural gas properties whereby costs incurred to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells, and expenditures for enhanced recovery operations are capitalized. Geological and geophysical costs, seismic costs incurred for exploratory projects, lease rentals and costs associated with unsuccessful exploratory wells or projects are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. To the extent a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between capitalized development costs and exploration expense. Maintenance, repairs and costs of injection are expensed as incurred, except that the costs of replacements or renewals that expand capacity or improve production are capitalized.

Under the successful efforts method of accounting, the Company capitalizes exploratory drilling costs on the balance sheet pending determination of whether the well has found proved reserves in economically producible quantities. The Company capitalizes costs associated with the acquisition or construction of support equipment and facilities with the drilling and development costs to which they relate. If proved reserves are found by an exploratory well, the associated capitalized costs become part of well equipment and facilities. However, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value.

Production expenses are those costs incurred by the Company to operate and maintain its crude oil and natural gas properties and associated equipment and facilities. Production expenses include but are not limited to labor costs to operate the Company's properties, repairs and maintenance, waste water disposal costs, utility costs, certain workover-related costs, and materials and supplies utilized in the Company's operations.

Service property and equipment

Service property and equipment consist primarily of automobiles and aircraft; machinery and equipment; gathering and recycling systems; storage tanks; office and computer equipment, software, furniture and fixtures; and buildings and improvements. Major renewals and replacements are capitalized and stated at cost, while maintenance and repairs are expensed as incurred.

Depreciation and amortization of service property and equipment are provided in amounts sufficient to expense the cost of depreciable assets to operations over their estimated useful lives using the straight-line method. The estimated useful lives of service property and equipment are as follows:

| Service property and equipment | Useful Lives In Years |
|---|---|
| Automobiles and aircraft | 5-10 |
| Machinery and equipment | 6-10 |
| Gathering and recycling systems | 15-30 |
| Storage tanks | 10-30 |
| Office and computer equipment, software, furniture and fixtures | 3-25 |
| Buildings and improvements | 4-40 |

Depreciation, depletion and amortization

Depreciation, depletion and amortization of capitalized drilling and development costs of producing crude oil and natural gas properties, including related support equipment and facilities, are computed using the unit-of-production method on a field basis based on total estimated proved developed reserves. Amortization of producing leaseholds is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable crude oil and natural gas reserves are established based on estimates made by the Company's internal geologists and engineers and external independent reserve engineers. Upon sale or retirement of properties, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least in conjunction with semi-annual reserve reports. Revisions are accounted for prospectively as changes in accounting estimates.

Asset retirement obligations

The Company accounts for its asset retirement obligations by recording the fair value of a liability for an asset retirement obligation in the period in which a legal obligation is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the capitalized asset retirement costs are charged to expense through the depreciation, depletion and amortization of crude oil and natural gas properties and the liability is accreted to the expected future abandonment cost ratably over the related asset's life.

The Company's primary asset retirement obligations relate to future plugging and abandonment costs and related disposal of facilities on its crude oil and natural gas properties. The following table summarizes the changes in the Company's future abandonment liabilities from January 1, 2015 through December 31, 2017:

| In thousands | 2017 | 2016 | 2015 |
|---|---|---|---|
| Asset retirement obligations at January 1 | $96,178 | $102,909 | $76,708 |
| Accretion expense | 5,886 | 6,086 | 4,740 |
| Revisions (1) | 7,801 | (12,755) | 15,068 |
| Plus: Additions for new assets | 6,884 | 2,692 | 7,404 |
| Less: Plugging costs and sold assets | (2,343) | (2,754) | (1,011) |
| Total asset retirement obligations at December 31 | $114,406 | $96,178 | $102,909 |
| Less: Current portion of asset retirement obligations at December 31 (2) | 2,612 | 1,742 | 1,658 |
| Non-current portion of asset retirement obligations at December 31 | $111,794 | $94,436 | $101,251 |

(1) Revisions primarily represent changes in the present value of liabilities resulting from changes in estimated costs and economic lives of producing properties.

(2) Balance is included in the caption "Accrued liabilities and other" in the consolidated balance sheets.

As of December 31, 2017 and 2016, net property and equipment on the consolidated balance sheets included $40.3 million and $34.0 million, respectively, of net asset retirement costs.

Asset impairment

Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value.

Non-producing crude oil and natural gas properties primarily consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Impairment losses for non-producing properties are recognized by amortizing the portion of the properties' costs which management estimates will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period. The Company's impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms, and potential shifts in business strategy employed by management.

Debt issuance costs

Costs incurred in connection with the execution of the Company's note payable and revolving credit facility and any amendments thereto are capitalized and amortized over the terms of the arrangements on a straight-line basis, the use of which approximates the effective interest method. Costs incurred upon the issuances of the Company's various senior notes (collectively, the "Notes") were capitalized and are being amortized over the terms of the Notes using the effective interest method.

The Company had aggregate capitalized costs of $58.2 million and $55.9 million (net of accumulated amortization of $65.9 million and $56.8 million) relating to its long-term debt at December 31, 2017 and 2016, respectively. Unamortized capitalized costs associated with the Company's Notes and note payable totaled $55.0 million and $50.4 million at December 31, 2017 and 2016, respectively, and are reflected as a reduction of "Long-term debt, net of current portion" on the consolidated balance sheets. The increase in 2017 resulted from the capitalization of costs incurred in connection with the Company's issuance of 4.375% Senior Notes due 2028 as discussed in Note 7. Long-Term Debt. Unamortized capitalized costs associated with the Company's revolving credit facility totaled $3.2 million and $5.5 million at December 31, 2017 and 2016, respectively, and are reflected in "Other noncurrent assets" on the consolidated balance sheets.

For the years ended December 31, 2017, 2016 and 2015, the Company recognized amortization expense associated with capitalized debt issuance costs of $9.1 million, $9.8 million and $8.9 million, respectively, which are reflected in

"Interest expense" on the consolidated statements of comprehensive income (loss).

Derivative instruments

The Company recognizes its derivative instruments on the balance sheet as either assets or liabilities measured at fair value with such amounts classified as current or long-term based on contractual settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the changes in fair value in the consolidated statements of comprehensive income (loss). Gains and losses on crude oil and natural gas derivatives are reflected in the caption "Gain (loss) on crude oil and natural gas derivatives, net." Gains and losses on diesel fuel derivatives are reflected in the caption "Operating costs and expenses—Net gain on sale of assets and other."

Fair value of financial instruments

The Company's financial instruments consist primarily of cash, trade receivables, trade payables, derivative instruments and long-term debt. See Note 6. Fair Value Measurements for a discussion of the methods used to determine fair value for the Company's financial instruments and the quantification of fair value for its derivatives and long-term debt obligations at December 31, 2017 and 2016.

Income taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. On December 22, 2017, the Tax Cuts and Jobs Act (the "Tax Reform Act") was signed into law, which among other things reduces the federal corporate income tax rate from 35% to 21% effective January 1, 2018. In accordance with U.S. GAAP, the Company remeasured its deferred income tax assets and liabilities as of December 31, 2017 to reflect the reduced tax rate. See Note 8. Income Taxes for further discussion of the Tax Reform Act and its impact on the Company's financial statements as of and for the year ended December 31, 2017.

The Company's policy is to recognize penalties and interest related to unrecognized tax benefits, if any, in income tax expense. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. The Company recorded valuation allowances of $0.4 million, $1.0 million, and $13.5 million for the years ended December 31, 2017, 2016, and 2015, respectively, against deferred tax assets associated with operating loss carryforwards generated by its Canadian subsidiary for which the Company does not expect to realize a benefit.

Earnings per share

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of shares outstanding for the period. In periods where the Company has net income, diluted earnings per share reflects the potential dilution of non-vested restricted stock awards, which are calculated using the treasury stock method. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income (loss) per share for the years ended December 31, 2017, 2016 and 2015.

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands, except per share data | 2017 | 2016 | 2015 |
| Net income (loss) (numerator) (1) | $789,447 | $(399,679) | $(353,668) |
| Weighted average shares (denominator): | | | |
| Weighted average shares - basic | 371,066 | 370,380 | 369,540 |
| Non-vested restricted stock (2) | 2,702 | — | — |
| Weighted average shares - diluted | 373,768 | 370,380 | 369,540 |
| Net income (loss) per share: (1) | | | |
| Basic | $2.13 | $(1.08) | $(0.96) |
| Diluted | $2.11 | $(1.08) | $(0.96) |

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(1) The Company's remeasurement of its deferred income tax assets and liabilities in response to the enactment of the Tax Reform Act in December 2017 resulted in a one-time decrease in income tax expense and corresponding increase in net income of approximately $713.7 million ($1.92 per basic share and $1.91 per diluted share) for the year ended December 31, 2017. See Note 8. Income Taxes for further discussion. Additionally, 2017 results include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement as discussed in Note 10. Commitments and Contingencies, which resulted in an after-tax decrease in 2017 net income of $37.0 million ($0.10 per basic and diluted share).

(2) For the years ended December 31, 2016 and 2015, the Company had a net loss and therefore the potential dilutive effect of approximately 2,303,000 and 1,567,000 weighted average non-vested restricted shares, respectively, were not included in the calculation of diluted net loss per share because to do so would have been anti-dilutive to the computations.

Foreign currency translation

In 2014, the Company initiated exploratory drilling activities in Canada through a 100%-owned Canadian subsidiary. The Company's operations in Canada are currently immaterial. The Company has designated the Canadian dollar as the functional currency for its Canadian operations. Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in "Accumulated other comprehensive income (loss)" within shareholders' equity on the consolidated balance sheets.

Adoption of new accounting pronouncements

Stock-based compensation – In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-09, Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which changes how companies account for certain aspects of share-based payment awards, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The Company adopted the new standard on January 1, 2017 as required. The impact of adoption is described below.

ASU 2016-09 removes the requirement to delay recognition of an excess tax benefit until it reduces current taxes payable. An excess tax benefit (tax deficiency) arises when stock-based compensation expense recognized in an entity's tax return exceeds (is less than) the expense recognized in an entity's financial statements. Under the new standard, effective January 1, 2017 excess tax benefits are recorded when they arise. This change was required to be applied on a modified retrospective basis by recording a cumulative effect adjustment to opening retained earnings upon adoption to account for previously unrecognized excess tax benefits. The Company's cumulative effect adjustment recorded under the new standard resulted in a $5.2 million increase in retained earnings and corresponding decrease in deferred income tax liabilities at January 1, 2017.

Additionally, under ASU 2016-09 companies no longer record excess tax benefits and deficiencies in additional paid-in capital. Instead, excess tax benefits and deficiencies are recognized as income tax benefit or expense in the income statement, effective January 1, 2017 on a prospective basis. This is expected to result in increased volatility in income tax expense/benefit and corresponding variations in the relationship between income tax expense/benefit and pre-tax income/loss from period to period. The Company recognized $3.9 million ($0.01 per basic and diluted share) of tax deficiencies from stock-based compensation as income tax expense for the year ended December 31, 2017 under the new standard, which is reflected in "Benefit for income taxes" in the consolidated statements of comprehensive income (loss).

ASU 2016-09 also removed the requirement that entities present excess tax benefits and deficiencies as offsetting cash flows from financing and operating activities in the statement of cash flows. Instead, ASU 2016-09 requires cash flows related to excess tax benefits and deficiencies be classified as operating activities in the same manner as other cash flows related to income taxes. The Company has elected to apply this guidance on a prospective basis. Accordingly, the cash flow presentation of excess tax benefits and deficiencies in periods prior to January 1, 2017 has not been adjusted to conform to current period presentation.

The Company has elected to continue its historical accounting practice of estimating forfeitures in determining the amount of stock-based compensation expense to recognize. Therefore, the adoption of ASU 2016-09 does not have an impact on the amount of stock-based compensation expense to be recognized by the Company on non-vested restricted stock awards.

Business combinations – In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which changes the definition of a business to assist entities with evaluating when a set of transferred assets and activities is deemed to be a business. Determining whether a transferred set constitutes a business is important because the accounting for a business combination differs from that of an asset acquisition. The definition of a business also affects the accounting for dispositions. Under the new standard, when substantially all of the fair value of assets acquired is concentrated in a single asset, or a group of similar assets, the assets acquired would not represent a business and business combination accounting would not be required. The new standard may result in more transactions being accounted for as asset acquisitions rather than business combinations. The standard is effective for interim and annual periods beginning after December 15, 2017 and shall be applied prospectively. The Company early adopted ASU 2017-01 as of January 1, 2017, which had no significant impact on the Company's financial statements as of and for the year ended December 31, 2017.

New accounting pronouncements not yet adopted at December 31, 2017

Revenue recognition and presentation – In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which generally requires an entity to identify performance obligations in its contracts, estimate the amount of consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation, and recognize revenue as obligations are satisfied. Additionally, the standard requires expanded disclosures related to revenue recognition.

Subsequent to the issuance of ASU 2014-09, the FASB issued various clarifications and interpretive guidance to assist entities with implementation efforts, including guidance pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. Under this guidance, an entity generally shall record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity shall record revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer. Significant judgment may be required in some circumstances to determine whether gross or net presentation is appropriate.

ASU 2014-09 and related interpretive guidance is effective for interim and annual periods beginning after December 15, 2017 and allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company adopted the standard on January 1, 2018 using the modified retrospective approach, which had no cumulative effect impact on retained earnings upon adoption. The standard is not expected to have a material effect on the timing of the Company's revenue recognition or its financial position, results of operations, net income, or cash flows, but will impact the Company's revenue-related disclosures and internal controls over financial reporting beginning January 1, 2018. Additionally, the standard will impact the Company's future presentation of revenues and expenses under the gross-versus-net presentation guidance. Historically, the Company has generally presented its revenues net of transportation costs. The new guidance will result in future revenues and associated transportation expenses for certain of the Company's operated properties being reported on a gross basis beginning January 1, 2018. The changes from net to gross presentation will result in an increase in revenues and a corresponding increase in separately reported transportation expenses, with no net effect on the Company's results of operations, net income, or cash flows. For the year ended December 31, 2017, the Company had approximately $201.5 million of transportation–related charges on operated properties included in "Crude oil and natural gas sales" on the consolidated statements of comprehensive income (loss). This amount is not necessarily indicative of amounts to be expected in future periods. The Company is not able to estimate the impact on the presentation of its future revenues and expenses under the new guidance due to uncertainties with respect to future sales volumes, service costs, locations of producing properties, sales destinations, transportation methods utilized, and changes in the nature, timing, and extent of its arrangements from period to period.

Leases – In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires companies to recognize a right of use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than 12 months. The standard is effective for interim and annual reporting periods beginning after December 15, 2018 and requires adoption by application of a modified retrospective transition approach.

The Company continues to evaluate the impact of ASU 2016-02 on its financial statements, accounting policies and internal controls and is in the process of developing systems and processes to identify, classify, and account for leases within the scope of the new guidance and to comply with the related disclosure requirements. Standard setting guidance and interpretations continue to evolve and are being monitored for applicability and impact to the Company's business and industry. Based on an initial review of the new guidance and the Company's current commitments, the Company anticipates it may be required to recognize lease assets and liabilities related to drilling rig commitments, certain equipment rentals and leases, certain surface use agreements, and potentially certain firm transportation agreements, as well as other arrangements, the effect of which cannot be estimated at this time.

Credit losses – In June 2016, the FASB issued ASU 2016-13, Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. This standard changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost. The standard is effective for interim and annual periods beginning after December 15, 2019 and shall be applied using a modified retrospective approach resulting in a cumulative effect adjustment to retained earnings upon adoption. The Company continues to evaluate the new standard and is unable to estimate its financial statement impact at this time. Historically, the Company's credit losses on crude oil and natural gas sales receivables and joint interest receivables have been immaterial.

Note 2. Supplemental Cash Flow Information

The following table discloses supplemental cash flow information about cash paid for interest and income tax payments and refunds. Also disclosed is information about investing activities that affects recognized assets and liabilities but does not result in cash receipts or payments.

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Supplemental cash flow information: | | | |
| Cash paid for interest | $281,058 | $316,116 | $301,743 |
| Cash paid for income taxes | 2 | 2 | 30 |
| Cash received for income tax refunds | 257 | 174 | 61,403 |
| Non-cash investing activities: | | | |
| Asset retirement obligation additions and revisions, net | 14,685 | (10,063) | 22,472 |

As of December 31, 2017 and 2016, the Company had $302.8 million and $223.6 million, respectively, of accrued capital expenditures included in "Net property and equipment" and "Accounts payable trade" in the consolidated balance sheets.

Note 3. Net Property and Equipment

Net property and equipment includes the following at December 31, 2017 and 2016.

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Proved crude oil and natural gas properties | $21,362,199 | $19,802,395 |
| Unproved crude oil and natural gas properties | 365,413 | 429,562 |
| Service properties, equipment and other | 290,111 | 301,788 |
| Total property and equipment | 22,017,723 | 20,533,745 |
| Accumulated depreciation, depletion and amortization | (9,083,934) | (7,652,518) |
| Net property and equipment | $12,933,789 | $12,881,227 |

Note 4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2017 and 2016:

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Prepaid advances from joint interest owners | $34,511 | $57,861 |
| Accrued compensation | 65,308 | 38,046 |
| Accrued production taxes, ad valorem taxes and other non-income taxes | 40,611 | 22,053 |
| Accrued interest | 55,282 | 52,657 |
| Accrued litigation settlement (see Note 10) | 59,600 | — |
| Current portion of asset retirement obligations | 2,612 | 1,742 |
| Other | 2,150 | 4,411 |
| Accrued liabilities and other | $260,074 | $176,770 |

Note 5. Derivative Instruments

Crude oil and natural gas derivatives

The Company may utilize crude oil and natural gas swap and collar derivative contracts to economically hedge against the variability in cash flows associated with future sales of crude oil and natural gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements.

The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its crude oil and natural gas derivative instruments as hedges for accounting purposes and, as a result, marks such derivative instruments to fair value and recognizes the changes in fair value in the consolidated statements of comprehensive income (loss) under the caption “Gain (loss) on crude oil and natural gas derivatives, net.”

The estimated fair value of derivative contracts is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars and written call options, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars and written call options requires the use of an option-pricing model. See Note 6. Fair Value Measurements.

With respect to a crude oil or natural gas fixed price swap contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a crude oil or natural gas collar contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is between the floor price and the ceiling price.

At December 31, 2017, the Company had outstanding natural gas derivative contracts as set forth in the table below. The volumes reflected below represent an aggregation of multiple derivative contracts having similar remaining durations expected to be realized ratably over the indicated 2018 period. At December 31, 2017 the Company had no outstanding crude oil derivative contracts.

| Period and Type of Contract | MMBtus | Swaps Weighted Average Price |
|---|---|---|
| January 2018 - March 2018 | | |
| Swaps - Henry Hub | 6,300,000 | $ 3.28 |

Crude oil and natural gas derivative gains and losses

Cash receipts and payments in the following table reflect the gain or loss on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period end, if any, and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Cash received (paid) on derivatives: | | | |
| Natural gas fixed price swaps | $40,095 | $88,823 | $39,670 |
| Natural gas collars | (10,539 ) | — | 29,883 |
| Cash received on derivatives, net | 29,556 | 88,823 | 69,553 |
| Non-cash gain (loss) on derivatives: | | | |
| Crude oil written call options | — | 38 | 4,715 |
| Natural gas fixed price swaps | 18,960 | (120,784 ) | 41,828 |
| Natural gas collars | 43,131 | (39,936 ) | (25,011 ) |
| Non-cash gain (loss) on derivatives, net | 62,091 | (160,682 ) | 21,532 |
| Gain (loss) on crude oil and natural gas derivatives, net | $91,647 | $(71,859 ) | $91,085 |

Diesel fuel derivatives

The Company previously entered into diesel fuel swap derivative contracts, all of which matured on or before December 31, 2017, to economically hedge against the variability in cash flows associated with future purchases of diesel fuel for use in drilling activities. With respect to the diesel fuel swap contracts, the counterparty was required to make a payment to the Company if the settlement price for any settlement period was greater than the swap price, and the Company was required to make a payment to the counterparty if the settlement price for any settlement period was less than the swap price. The diesel fuel swap contracts were settled based upon reported NYMEX settlement prices for New York Harbor ultra-low sulfur diesel fuel.

The Company recognized its diesel fuel derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The estimated fair value was based upon various factors, including commodity exchange prices, over-the-counter quotations, the risk-free interest rate, and time to expiration. The Company did not designate its diesel fuel derivative instruments as hedges for accounting purposes and, as a result, marked the derivative instruments to fair value and recognized the changes in fair value in the consolidated statements of comprehensive income (loss) under the caption “Operating costs and expenses—Net gain on sale of assets and other.”

Cash receipts in the following table reflect gains on diesel fuel derivatives which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of diesel fuel derivatives held at period end, if any, and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

| | Year ended December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Cash received on diesel fuel derivatives | $2,845 | $699 |
| Non-cash gain (loss) on diesel fuel derivatives | (4,060 ) | 4,060 |
| Gain (loss) on diesel fuel derivatives, net | $(1,215 ) | $4,759 |

Balance sheet offsetting of derivative assets and liabilities

The Company’s derivative contracts are recorded at fair value in the consolidated balance sheets under the captions “Derivative assets”, “Noncurrent derivative assets”, “Derivative liabilities”, and “Noncurrent derivative liabilities”, as applicable. Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the consolidated balance sheets.

The following table presents the gross amounts of recognized crude oil, natural gas, and diesel fuel derivative assets and liabilities, as applicable, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets for the periods presented, all at fair value.

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Commodity derivative assets: | | |
| Gross amounts of recognized assets | $2,603 | $4,061 |
| Gross amounts offset on balance sheet | — | — |
| Net amounts of assets on balance sheet | 2,603 | 4,061 |
| Commodity derivative liabilities: | | |
| Gross amounts of recognized liabilities | — | (59,489 ) |
| Gross amounts offset on balance sheet | — | — |
| Net amounts of liabilities on balance sheet | $— | $(59,489) |

The following table reconciles the net amounts disclosed above to the individual financial statement line items in the consolidated balance sheets.

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Derivative assets | $2,603 | $4,061 |
| Noncurrent derivative assets | — | — |
| Net amounts of assets on balance sheet | 2,603 | 4,061 |
| Derivative liabilities | — | (59,489 ) |
| Noncurrent derivative liabilities | — | — |
| Net amounts of liabilities on balance sheet | — | (59,489 ) |
| Total derivative assets (liabilities), net | $2,603 | $(55,428) |

Note 6. Fair Value Measurements

The Company follows a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2: Observable market-based inputs or unobservable inputs corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3: Unobservable inputs not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

A financial instrument's categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the hierarchy. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available. The Company's policy is to recognize transfers between the hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

Continental Resources, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

Assets and liabilities measured at fair value on a recurring basis

The Company's derivative instruments are reported at fair value on a recurring basis. In determining the fair values of swap contracts, a discounted cash flow method is used due to the unavailability of relevant comparable market data for the Company's exact contracts. The discounted cash flow method estimates future cash flows based on quoted market prices for forward commodity prices and a risk-adjusted discount rate. The fair values of swap contracts are calculated mainly using significant observable inputs (Level 2). Calculation of the fair values of collars requires the use of an industry-standard option pricing model that considers various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. These assumptions are observable in the marketplace or can be corroborated by active markets or broker quotes and are therefore designated as Level 2 within the valuation hierarchy. The Company's calculation of fair value for each of its derivative positions is compared to the counterparty valuation for reasonableness.

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2017 and 2016.

| | Fair value measurements at December 31, 2017 using: | | | |
|---|---|---|---|---|
| In thousands | Level 1 | Level 2 | Level 3 | Total |
| Derivative assets: | | | | |
| Swaps | $ — | $ 2,603 | $ — | $ 2,603 |
| Total | $ — | $ 2,603 | $ — | $ 2,603 |

| | Fair value measurements at December 31, 2016 using: | | | |
|---|---|---|---|---|
| In thousands | Level 1 | Level 2 | Level 3 | Total |
| Derivative liabilities: | | | | |
| Swaps | $ — | $ (12,297) | $ — | $ (12,297) |
| Collars | — | (43,131) | — | (43,131) |
| Total | $ — | $ (55,428) | $ — | $ (55,428) |

Assets measured at fair value on a nonrecurring basis

Certain assets are reported at fair value on a nonrecurring basis in the consolidated financial statements. The following methods and assumptions were used to estimate the fair values for those assets.

Asset impairments – Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field is reduced to its estimated fair value. Risk-adjusted probable and possible reserves may be taken into consideration when determining estimated future net cash flows and fair value when such reserves exist and are economically recoverable. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on the Company's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips adjusted for differentials, operating costs, and a risk-adjusted discount rate. The fair value of proved crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3). The following table sets forth quantitative information about the significant unobservable inputs used by the Company at December 31, 2017 to calculate the fair value of proved crude oil and natural gas properties using a discounted cash flow method.

| Unobservable Input | Assumption |
|---|---|
| Future production | Future production estimates for each property |

| | |
|---|---|
| Forward commodity prices | Forward NYMEX strip prices through 2022 (adjusted for differentials), escalating 3% per year thereafter |
| Operating costs | Estimated costs for the current year, escalating 3% per year thereafter |
| Productive life of field | Ranging from 1 to 38 years |
| Discount rate | 10% |

Unobservable inputs to the fair value assessment are reviewed quarterly and are revised as warranted based on a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Fair value measurements of proved properties are reviewed and approved by certain members of the Company's management.

For the year ended December 31, 2017, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows, and therefore, were impaired. Impairments of proved properties amounted to $82.3 million for 2017, which reflect fair value adjustments in the Arkoma Woodford field ($81.2 million) and various non-core areas in the North and South regions ($1.1 million). The impaired properties were written down to their estimated fair value at the time of impairment of approximately $72 million.

Certain unproved crude oil and natural gas properties were impaired during the years ended December 31, 2017, 2016, and 2015, reflecting recurring amortization of undeveloped leasehold costs on properties the Company expects will not be transferred to proved properties over the lives of the leases based on drilling plans, experience of successful drilling, and the average holding period.

The following table sets forth the non-cash impairments of both proved and unproved properties for the indicated periods. Proved and unproved property impairments are recorded under the caption "Property impairments" in the consolidated statements of comprehensive income (loss).

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Proved property impairments | $82,340 | $2,895 | $138,878 |
| Unproved property impairments | 155,030 | 234,397 | 263,253 |
| Total | $237,370 | $237,292 | $402,131 |

Financial instruments not recorded at fair value

The following table sets forth the estimated fair values of financial instruments that are not recorded at fair value in the consolidated financial statements.

| | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| In thousands | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Debt: | | | | |
| Revolving credit facility (1) | $188,000 | $188,000 | $905,000 | $905,000 |
| Term loan (1) | — | — | 498,865 | 500,000 |
| Note payable | 9,974 | 9,900 | 12,176 | 10,200 |
| 5% Senior Notes due 2022 | 1,997,576 | 2,040,000 | 1,997,188 | 2,020,400 |
| 4.5% Senior Notes due 2023 | 1,486,690 | 1,526,800 | 1,484,524 | 1,474,800 |
| 3.8% Senior Notes due 2024 | 992,036 | 988,800 | 990,964 | 929,400 |
| 4.375% Senior Notes due 2028 (1) | 988,061 | 987,200 | — | — |
| 4.9% Senior Notes due 2044 | 691,354 | 679,900 | 691,199 | 607,600 |
| Total debt | $6,353,691 | $6,420,600 | $6,579,916 | $6,447,400 |

(1) In December 2017, the Company issued $1.0 billion of 4.375% Senior Notes due 2028 and used the proceeds therefrom to repay in full and terminate its term loan and to repay a portion of the borrowings outstanding under its revolving credit facility. See Note 7. Long-Term Debt for further discussion.

The fair values of revolving credit facility borrowings and the term loan approximate carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and are classified as Level 2 in the fair value hierarchy.

The fair value of the note payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the note payable and an assumed discount rate. The fair value of the note payable is significantly influenced by the discount rate assumption, which is derived by the Company and is unobservable. Accordingly, the fair value of the note payable is classified as Level 3 in the fair value hierarchy.

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The fair values of the 5% Senior Notes due 2022 (“2022 Notes”), the 4.5% Senior Notes due 2023 (“2023 Notes”), the 3.8% Senior Notes due 2024 (“2024 Notes”), the 4.375% Senior Notes due 2028 (“2028 Notes”), and the 4.9% Senior Notes due 2044 (“2044 Notes”) are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.
The carrying values of all classes of cash and cash equivalents, trade receivables, and trade payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.
Note 7. Long-Term Debt
Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $44.3 million and $37.3 million at December 31, 2017 and 2016, respectively, consists of the following.

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Revolving credit facility | $188,000 | $905,000 |
| Term loan | — | 498,865 |
| Note payable | 9,974 | 12,176 |
| 5% Senior Notes due 2022 | 1,997,576 | 1,997,188 |
| 4.5% Senior Notes due 2023 | 1,486,690 | 1,484,524 |
| 3.8% Senior Notes due 2024 | 992,036 | 990,964 |
| 4.375% Senior Notes due 2028 | 988,061 | — |
| 4.9% Senior Notes due 2044 | 691,354 | 691,199 |
| Total debt | 6,353,691 | 6,579,916 |
| Less: Current portion of long-term debt | 2,286 | 2,219 |
| Long-term debt, net of current portion | $6,351,405 | $6,577,697 |

Revolving credit facility
The Company has an unsecured revolving credit facility, maturing on May 16, 2019, with aggregate commitments totaling $2.75 billion at December 31, 2017. Credit facility borrowings bear interest at market-based interest rates plus a margin based on the terms of the borrowing and the credit ratings assigned to the Company’s senior, unsecured, long-term indebtedness. The weighted-average interest rate on outstanding credit facility borrowings at December 31, 2017 was 3.19%.
The Company had approximately $2.56 billion of borrowing availability on its revolving credit facility at December 31, 2017 and incurs commitment fees based on currently assigned credit ratings of 0.30% per annum on the daily average amount of unused borrowing availability under its revolving credit facility.
The revolving credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (calculated as total face value of debt plus outstanding letters of credit less cash and cash equivalents) divided by the sum of net debt plus total shareholders’ equity plus, to the extent resulting in a reduction of total shareholders’ equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with the revolving credit facility covenants at December 31, 2017.
Senior notes
In December 2017, the Company issued $1.0 billion of 4.375% Senior Notes due 2028 and received total net proceeds of $990 million after deducting the initial purchasers' fees. The 2028 Notes were sold at par in a private placement transaction exempt from the registration requirements of the Securities Act to qualified institutional buyers in reliance on Rule 144A of the Securities Act. The Company used the net proceeds from the offering to repay in full and terminate its $500 million term loan and to repay a portion of the borrowings outstanding under its revolving credit facility.
In connection with the issuance of the 2028 Notes, the Company entered into a registration rights agreement with the initial purchasers dated December 8, 2017 to allow holders of the unregistered 2028 Notes to exchange them for

registered notes that have substantially identical terms. The Company agreed to use reasonable efforts to cause the exchange to be completed within 400 days after the issuance of the 2028 Notes. The Company is required to pay additional interest if it fails to comply with its obligations to register the 2028 Notes within the specified time period, whereby the interest rate would be increased by

1.0% per annum during the period in which a registration default is in effect. The Company expects to comply with the terms of the registration rights agreement and complete the exchange of the 2028 Notes within the 400 day period.
The following table summarizes the face values, maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company's outstanding senior note obligations at December 31, 2017.

| | 2022 Notes (1) | 2023 Notes | 2024 Notes | 2028 Notes | 2044 Notes |
|---|---|---|---|---|---|
| Face value (in thousands) | $2,000,000 | $1,500,000 | $1,000,000 | $1,000,000 | $700,000 |
| Maturity date | Sep 15, 2022 | April 15, 2023 | June 1, 2024 | January 15, 2028 | June 1, 2044 |
| Interest payment dates | March 15, Sep 15 | April 15, Oct 15 | June 1, Dec 1 | Jan 15, July 15 | June 1, Dec 1 |
| Make-whole redemption period (2) | — | Jan 15, 2023 | Mar 1, 2024 | Oct 15, 2027 | Dec 1, 2043 |

(1) The Company has the option to redeem all or a portion of its 2022 Notes at the decreasing redemption prices specified in the indenture related to the 2022 Notes plus any accrued and unpaid interest to the date of redemption.

(2) At any time prior to the indicated dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series at the "make-whole" redemption prices or amounts specified in the respective senior note indentures plus any accrued and unpaid interest to the date of redemption. On or after these dates, the Company may redeem all or a portion of its senior notes at a redemption price equal to 100% of the principal amount of the senior notes being redeemed plus any accrued and unpaid interest to the date of redemption.

The Company's senior notes are not subject to any mandatory redemption or sinking fund requirements.
The indentures governing the Company's senior notes contain covenants that, among other things, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, or consolidate, merge or transfer certain assets. The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at December 31, 2017. Three of the Company's subsidiaries, Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, and The Mineral Resources Company, which have no material assets or operations, fully and unconditionally guarantee the senior notes on a joint and several basis. The Company's other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

2016 Redemptions of Senior Notes

In November 2016, the Company redeemed its then outstanding 7.375% Senior Notes due 2020 ("2020 Notes") and 7.125% Senior Notes due 2021 ("2021 Notes"). The redemption price for the 2020 Notes was equal to 102.458% of the $200 million principal amount plus accrued and unpaid interest to the redemption date in accordance with the terms of the 2020 Notes and related indenture. The redemption price for the 2021 Notes was equal to 103.563% of the $400 million principal amount plus accrued and unpaid interest to the redemption date in accordance with the terms of the 2021 Notes and related indenture. The aggregate of the principal amounts, redemption premiums, and accrued interest paid upon redemption of the 2020 Notes and 2021 Notes was $623.9 million. The Company funded the redemptions using borrowings under its revolving credit facility.
The Company recognized a pre-tax loss totaling $26.1 million related to the redemptions, which included the call premiums and write-off of deferred financing costs and unaccreted debt discounts associated with the notes and is reflected under the caption "Loss on extinguishment of debt" in the consolidated statements of comprehensive income (loss) for the year ended December 31, 2016.

Term loan

In November 2015, the Company borrowed $500 million under a three-year term loan agreement which was scheduled to mature on November 4, 2018. In December 2017, the Company repaid in full and terminated the term loan using a portion of the proceeds from its issuance of 2028 Notes as described above. The Company recognized a pre-tax loss on extinguishment of $0.6 million related to the termination, representing the write-off of deferred financing costs associated with the term loan.

Note payable

In February 2012, 20 Broadway Associates LLC, a 100% owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.3 million is reflected as a current liability under the caption "Current portion of long-term debt" in the consolidated balance sheets as of December 31, 2017.

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Note 8. Income Taxes

On December 22, 2017, the Tax Reform Act was signed into law. The new legislation contains several key changes to U.S. corporate tax laws that are expected to impact the Company, including a reduction of the corporate income tax rate from 35% to 21%, effective January 1, 2018. The new legislation also includes a variety of other changes such as the repeal of the alternative minimum tax, the introduction of new limitations on the tax deductibility of net operating losses, interest expenses, and executive compensation expenses, the acceleration of expensing of certain qualified property, and the introduction of new laws governing taxation of foreign earnings of U.S. entities, among others.

U.S. GAAP (Accounting Standards Codification Topic 740, Income Taxes) requires entities to recognize the effect of tax law changes in the reporting period that includes the enactment date. The income tax accounting effect of a change in tax law includes, for example, remeasuring deferred tax assets and liabilities at a new tax rate and evaluating whether a valuation allowance is needed for deferred tax assets. In response to the enactment of the Tax Reform Act, the Securities and Exchange Commission issued guidance in Staff Accounting Bulletin No. 118 ("SAB 118") to assist entities in applying ASC 740 to the new tax law. SAB 118 allows entities to record estimated provisional amounts during a measurement period in circumstances where an entity does not have the necessary information in reasonable detail to complete its accounting for a tax law change under ASC 740 prior to the issuance of its financial statements.

In accordance with ASC 740, the Company remeasured its deferred tax assets and liabilities as of December 31, 2017 to reflect the reduction in the corporate tax rate from 35% to 21%. This remeasurement resulted in a $713.7 million decrease in net deferred income tax liabilities and corresponding decrease in income tax expense as of and for the year ended December 31, 2017, which is reflected in the tables below. The Company also reassessed the realizability of its deferred tax assets, taking into consideration how the new tax law impacts future taxable income, and has recorded such assets at realizable value at December 31, 2017. The Company's accounting for the effects of the tax rate change on its deferred tax balances as well as other relevant aspects of the Tax Reform Act is complete and no provisional amounts have been recorded as allowed under SAB 118.

The items comprising the Company's benefit for income taxes are as follows for the periods presented:

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Current income tax (provision) benefit: | | | |
| United States federal (1) | $7,781 | $22,941 | $— |
| Various states | — | (2) | (24) |
| Total current income tax (provision) benefit | 7,781 | 22,939 | (24) |
| Deferred income tax (provision) benefit: | | | |
| United States federal - taxation on operations | (81,054) | 182,422 | 140,578 |
| United States federal - effect of US tax reform | 713,655 | — | — |
| Various states | (7,002) | 27,414 | 40,863 |
| Total deferred income tax benefit | 625,599 | 209,836 | 181,441 |
| Benefit for income taxes | $633,380 | $232,775 | $181,417 |

(1) The current federal income tax benefits for the years ended December 31, 2017 and 2016 represent alternative minimum tax refunds.

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The benefit for income taxes differs from the amount computed by applying the United States statutory federal income tax rate to income (loss) before income taxes. The sources and tax effects of the difference are as follows:

| | Year ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2017 | | 2016 | | 2015 | |
| In thousands, except rates | Amount | Rate | Amount | Rate | Amount | Rate |
| Expected income tax (provision) benefit based on US statutory tax rate of 35% | $(54,623) | 35.0 % | $221,359 | 35.0% | $187,280 | 35.0% |
| State income taxes, net of federal benefit | (4,682) | 3.0 % | 18,829 | 3.0 % | 16,219 | 3.0 % |
| Effect of US tax reform legislation | 713,655 | (457.3%) | — | — % | — | — % |
| Tax deficiency from stock-based compensation (1) | (3,932) | 2.5 % | — | — % | — | — % |
| Canadian valuation allowance (2) | (404) | 0.3 % | (1,044) | (0.2 %) | (13,503) | (2.5 %) |
| Effect of differing statutory tax rate in Canada | (194) | 0.1 % | (481) | (0.1 %) | (5,239) | (1.0 %) |
| Non-deductible compensation | (13,813) | 8.9 % | (3,471) | (0.5 %) | (1,488) | (0.3 %) |
| Other, net | (2,627) | 1.7 % | (2,417) | (0.4 %) | (1,852) | (0.3 %) |
| Benefit for income taxes | $633,380 | (405.8%) | $232,775 | 36.8% | $181,417 | 33.9% |

(1) The Company recognized $3.9 million of tax deficiencies from stock-based compensation as income tax expense for the year ended December 31, 2017 in accordance with ASU 2016-09 as discussed in Note 1. Organization and Summary of Significant Accounting Policies–Adoption of new accounting pronouncements.

(2) Represents valuation allowances recognized against all deferred tax assets associated with operating loss carryforwards generated by the Company's Canadian operations during the respective periods for which the Company does not expect to realize a benefit.

The components of the Company’s deferred tax assets and deferred tax liabilities as of December 31, 2017 and 2016 are reflected in the table below.

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Deferred tax assets | | |
| United States net operating loss carryforwards | $604,423 | $478,975 |
| Canadian net operating loss carryforwards | 19,341 | 18,936 |
| Alternative minimum tax carryforwards | 7,781 | 16,663 |
| Equity compensation | 12,962 | 32,924 |
| Non-cash losses on derivatives | — | 21,064 |
| Other | 21,885 | 11,466 |
| Total deferred tax assets | 666,392 | 580,028 |
| Canadian valuation allowance | (19,341) | (18,936) |
| Total deferred tax assets, net of valuation allowance | 647,051 | 561,092 |
| Deferred tax liabilities | | |
| Property and equipment | (1,903,451) | (2,448,450) |
| Other | (3,158) | (2,947) |
| Total deferred tax liabilities | (1,906,609) | (2,451,397) |
| Deferred income tax liabilities, net | $(1,259,558) | $(1,890,305) |

As of December 31, 2017, the Company had federal and state net operating loss carryforwards of $2.39 billion and $3.40 billion, respectively. The federal net operating loss carryforward will begin expiring in 2033. The Company’s net operating loss carryforward in Oklahoma totaled $2.17 billion at December 31, 2017, which will begin to expire in 2027. The Company’s net operating loss carryforward in North Dakota totaled $1.07 billion at December 31, 2017, which will begin to expire in 2033. The Company has alternative minimum tax credit carryforwards of $7.8 million that are refundable by 2021. Any available statutory depletion carryforwards will be recognized when realized. The Company files income tax returns in the U.S. federal, U.S. state and Canadian jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2014.

The Company recorded valuation allowances of $0.4 million, $1.0 million and $13.5 million against Canadian deferred tax assets for the years ended December 31, 2017, 2016 and 2015, respectively. The Company's cumulative valuation allowance was $19.3 million as of December 31, 2017. Our Canadian subsidiary has generated operating loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change if our subsidiary generates taxable income.

Note 9. Lease Commitments

The Company’s operating lease obligations primarily represent leases for land and road use, office buildings and equipment, communication towers, and field equipment. Lease payments associated with operating leases for the years ended December 31, 2017, 2016 and 2015 were $1.9 million, $4.4 million and $9.6 million, respectively, a portion of which was capitalized and/or billed to other interest owners. At December 31, 2017, the minimum future rental commitments under operating leases having lease terms in excess of one year are reflected in the table below. New accounting rules will go into effect for reporting periods beginning after December 15, 2018 that will impact the Company's accounting for leases. See Note 1. Organization and Summary of Significant Accounting Policies–New accounting pronouncements not yet adopted at December 31, 2017–Leases for further discussion.

| In thousands | Total amount |
|---|---|
| 2018 | $1,656 |
| 2019 | 958 |
| 2020 | 817 |
| 2021 | 645 |
| 2022 | 620 |
| Thereafter | 7,208 |
| Total obligations | $11,904 |

Note 10. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of December 31, 2017. The commitments under these arrangements are not recorded in the accompanying consolidated balance sheets.

Drilling commitments – As of December 31, 2017, the Company has drilling rig contracts with various terms extending to February 2020 to ensure rig availability in its key operating areas. Future commitments as of December 31, 2017 total approximately $104 million, of which $73 million is expected to be incurred in 2018, $30 million in 2019 and $1 million in 2020. A portion of these future costs will be borne by other interest owners.

Transportation and processing commitments – The Company has entered into transportation and processing commitments to guarantee capacity on crude oil and natural gas pipelines and natural gas processing facilities. The commitments, which have varying terms extending as far as 2028, require the Company to pay per-unit transportation or processing charges regardless of the amount of capacity used. Future commitments remaining as of December 31, 2017 under the arrangements amount to approximately $1.43 billion, of which $197 million is expected to be incurred in 2018, $216 million in 2019, $186 million in 2020, $168 million in 2021, $166 million in 2022, and $497 million thereafter. A portion of these future costs will be borne by other interest owners. The Company is not committed under the above contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Litigation – In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition, as amended, alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and sought recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. The Company denied all allegations and denied that the case was properly brought as a class action. On June 11, 2015, the trial court certified a “hybrid” class requested by plaintiffs over the objections of the Company. The Company appealed the trial court’s class certification order. On February 8, 2017, the Oklahoma Court of Civil Appeals reversed the trial court’s ruling on certification and remanded the case for further proceedings. The plaintiffs filed a Petition for Rehearing which was denied by the Oklahoma Court of Civil Appeals. Plaintiffs then filed a Petition for Writ of Certiorari on May 23, 2017 to the Oklahoma Supreme Court, which was denied on October 2, 2017. On October 10, 2017, Plaintiffs filed with the trial court a "Second Amended and Renewed Motion for Class Action Certification and Request that the Court to Set a Briefing Schedule Related to Class Certification." During the litigation the Company was not able to estimate a reasonably possible loss or range of loss or what impact, if any, the ultimate resolution of the action would have on its financial condition, results of operations or cash flows due to the preliminary status of the matter, the complexity and number of legal and factual issues presented by the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the existence and the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter. The Company further disclosed that it was reasonably possible one or more events could occur in the near term that could impact the Company's ability to estimate the potential effect of this matter if any, on its financial condition, results of operations or cash flows. During the litigation the Company also disclosed plaintiffs alleged underpayments in excess of $200 million as damages, which may increase with the passage of time, a majority of which would be comprised of interest. After certification of the case as a class action was reversed the parties continued settlement negotiations. Due to the uncertainty of and burdens of litigation, on February 16, 2018, the Company reached a settlement in connection with this matter. Under the settlement, if approved by the court, the Company will make payments and incur costs associated with the settlement of approximately $59.6 million. The Company has accrued a loss for such amount, which is included in "Accrued liabilities and other" on the consolidated balance sheets and "Litigation settlement" in the consolidated statements of comprehensive income (loss) as of and for the year ended December 31, 2017. The District Court of Garfield County, Oklahoma must approve the settlement.

The Company is involved in various other legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, disputes with tax authorities and other matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. As of December 31, 2017 and 2016, the Company had recorded a liability in the consolidated balance sheets under the caption "Other noncurrent liabilities" of $7.6 million and $6.5 million, respectively, for various matters, none of which are believed to be individually significant.

Environmental risk – Due to the nature of the crude oil and natural gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

Note 11. Related Party Transactions

The Company historically sold a portion of its natural gas production to Hiland Partners, LP and its subsidiaries ("Hiland"). Hiland was controlled by the Company's principal shareholder through February 13, 2015, at which time it was sold to an unaffiliated third party. As a result of the sale, the prior related party relationship between the Company and Hiland terminated as of February 13, 2015. For the year ended December 31, 2015, sales to Hiland amounted to $1.4 million, net of transportation and processing costs, which is included in the caption "Crude oil and natural gas sales to affiliates" in the consolidated statements of comprehensive income (loss).

The Company capitalized costs of $0.1 million and $2.6 million in 2016 and 2015, respectively, associated with drilling rig services and demobilization of a drilling rig provided by an affiliate. Hiland historically provided field services such as compression, purchases of residue fuel gas and reclaimed crude oil, and reimbursements of generator rentals and fuel. Production and other expenses attributable to these transactions with Hiland prior to its sale were $1.7 million for the year ended December 31, 2015. The total amount paid to these affiliates, a portion of which was billed to other interest owners, was $0.1 million and $7.7 million for the years ended December 31, 2016 and 2015, respectively. No amounts were due to these affiliates at December 31, 2017 and 2016 related to the transactions.

Certain officers of the Company own or control entities that own working and royalty interests in wells operated by the Company. The Company paid revenues to these affiliates, including royalties, of $0.5 million, $0.4 million, and

$0.7 million and received payments from these affiliates of $0.3 million, $0.3 million, and $0.5 million during the years ended December 31, 2017, 2016, and 2015, respectively, relating to the operations of the respective properties. At December 31, 2017 and 2016, approximately $58,000 and $90,000 was due from these affiliates, respectively, and approximately $48,000 and $45,000 was due to these affiliates, respectively, relating to these transactions.

The Company allows certain affiliates to use its corporate aircraft and crews and has used the aircraft of those same affiliates from time to time in order to facilitate efficient transportation of Company personnel. The rates charged between the parties vary by type of aircraft used. In 2016, the Company also purchased an existing prepaid maintenance account from an affiliate for use in major engine overhaul to be applied as needed for corporate aircrafts. For usage during 2017, 2016, and 2015, the

Company charged affiliates approximately $19,400, $9,500, and $9,600, respectively, for use of its corporate aircraft crews, fuel, and reimbursement of expenses and received approximately $18,600, $6,800, and $33,000 from affiliates in 2017, 2016, and 2015, respectively. The Company was charged approximately $460,000, $292,000, and $236,000, respectively, by affiliates for use of their aircraft and reimbursement of expenses during 2017, 2016 (including the prepayment), and 2015 and paid $368,000, $195,000, and $221,000 to the affiliates in 2017, 2016, and 2015, respectively. At December 31, 2017 and 2016, approximately $4,200 and $3,400 was due from an affiliate, respectively, and approximately $92,000 and $97,000 was due to an affiliate, respectively, relating to these transactions.

The Company incurred costs for various field projects that had been ongoing with an entity that became an affiliate of the Company in the third quarter of 2014. During the fourth quarter of 2015, the affiliate relationship terminated. The total amount invoiced and capitalized for 2015 associated with the projects was $8.8 million. The total amount paid, a portion of which was billed to other interest owners, was $9.2 million for 2015.

Note 12. Stock-Based Compensation

On January 1, 2017, the Company adopted ASU 2016-09, Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. See Note 1. Organization and Summary of Significant Accounting Policies—Adoption of new accounting pronouncements for a discussion of the impact of adoption.

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2013 Long-Term Incentive Plan (“2013 Plan”) as discussed below. The Company’s associated compensation expense, which is included in the caption “General and administrative expenses” in the consolidated statements of comprehensive income (loss), was $45.9 million, $48.1 million, and $51.8 million for the years ended December 31, 2017, 2016 and 2015, respectively.

In May 2013, the Company adopted the 2013 Plan and reserved 19,680,072 shares of common stock that may be issued pursuant to the plan. As of December 31, 2017, the Company had 14,538,540 shares of common stock available for long-term incentive awards to employees and directors under the 2013 Plan.

Restricted stock is awarded in the name of the recipient and constitutes issued and outstanding shares of the Company’s common stock for all corporate purposes during the period of restriction and, except as otherwise provided under the 2013 Plan or agreement relevant to a given award, includes the right to vote the restricted stock and to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.

A summary of changes in non-vested restricted shares from December 31, 2014 to December 31, 2017 is presented below.

| | Number of non-vested shares | Weighted average grant-date fair value |
|---|---|---|
| Non-vested restricted shares at December 31, 2014 | 2,678,764 | $ 49.40 |
| Granted | 1,462,534 | 46.65 |
| Vested | (555,517) | 48.07 |
| Forfeited | (336,170) | 51.23 |
| Non-vested restricted shares at December 31, 2015 | 3,249,611 | $ 48.20 |
| Granted | 2,064,508 | 22.36 |
| Vested | (1,207,235) | 41.27 |
| Forfeited | (193,250) | 39.79 |
| Non-vested restricted shares at December 31, 2016 | 3,913,634 | $ 37.12 |
| Granted | 1,585,870 | 44.58 |
| Vested | (874,665) | 57.36 |

| | | |
|---|---|---|
| Forfeited | (598,729 ) | 37.34 |
| Non-vested restricted shares at December 31, 2017 | 4,026,110 | $ 35.63 |

The grant date fair value of restricted stock represents the closing market price of the Company’s common stock on the date of grant. Compensation expense for a restricted stock grant is determined at the grant date fair value and is recognized over the vesting period as services are rendered by employees and directors. The Company estimates the number of forfeitures expected to occur in determining the amount of stock-based compensation expense to recognize. There are no post-vesting restrictions

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related to the Company's restricted stock. The fair value at the vesting date of restricted stock that vested during 2017, 2016 and 2015 was $39.8 million, $30.0 million and $23.6 million, respectively. As of December 31, 2017, there was approximately $58 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.2 years.

Note 13. Accumulated Other Comprehensive Income (Loss)

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in "Accumulated other comprehensive income (loss)" within shareholders' equity on the consolidated balance sheets and "Other comprehensive income (loss), net of tax" in the consolidated statements of comprehensive income (loss). The following table summarizes the change in accumulated other comprehensive income (loss) for the years ended December 31, 2017, 2016, and 2015:

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Beginning accumulated other comprehensive loss, net of tax | $(260) | $(3,354) | $(385) |
| Foreign currency translation adjustments | 567 | 3,094 | (2,969) |
| Income taxes (1) | — | — | — |
| Other comprehensive income (loss), net of tax | 567 | 3,094 | (2,969) |
| Ending accumulated other comprehensive income (loss), net of tax | $307 | $(260) | $(3,354) |

(1) A valuation allowance has been recognized against all deferred tax assets associated with losses generated by the Company's Canadian operations, thereby resulting in no income taxes on other comprehensive income (loss).

Note 14. Property Dispositions

2017

In September 2017, the Company sold non-strategic properties in the Arkoma Woodford area for cash proceeds of $65.3 million. The sale included approximately 26,000 net acres of leasehold in Atoka, Coal, Hughes, and Pittsburg Counties of Oklahoma and producing properties with production totaling approximately 1,700 barrels of oil equivalent per day. In connection with the transaction, the Company recognized a pre-tax loss of $3.5 million for the year ended December 31, 2017. The disposed properties represented an immaterial portion of the Company's proved reserves.

In September 2017, the Company reached an agreement to sell non-core leasehold in the STACK play in Blaine County, Oklahoma for cash proceeds totaling $63.5 million. A portion of the transaction closed in September 2017, resulting in the receipt of proceeds amounting to $3.6 million and the recognition of a $3.3 million pre-tax gain on sale in the 2017 third quarter. The remainder of the transaction was completed in October 2017 at which time the Company received the remaining $59.9 million of proceeds and recognized an additional pre-tax gain of approximately $53.6 million, which is reflected in fourth quarter 2017 results. The disposed properties represented an immaterial portion of the Company's production and proved reserves.

In September 2017, the Company sold certain oil-loading facilities in Oklahoma for $7.2 million and recognized a $4.2 million pre-tax gain for the year ended December 31, 2017 associated with the transaction.

2016

In October 2016, the Company sold approximately 30,000 net acres of non-strategic leasehold in the SCOOP play in Oklahoma for cash proceeds totaling $295.6 million. The leasehold was located primarily in the eastern portion of the SCOOP play and included producing properties with production totaling approximately 700 barrels of oil equivalent per day. In connection with the transaction, the Company recognized a pre-tax gain of $201.0 million. The disposed properties represented an immaterial portion of the Company's proved reserves.

In September 2016, the Company sold non-strategic properties in North Dakota and Montana for cash proceeds totaling $214.8 million, with no gain or loss recognized. The sale included approximately 68,000 net acres of leasehold primarily in western Williams County, North Dakota, and approximately 12,000 net acres of leasehold in Roosevelt County, Montana. The sale also included producing properties with production totaling approximately 2,700 barrels of oil equivalent per day. The disposed properties represented an immaterial portion of the Company's proved reserves.

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In April 2016, the Company sold approximately 132,000 net acres of undeveloped leasehold acreage in Wyoming for cash proceeds totaling $110.0 million. In connection with the transaction, the Company recognized a pre-tax gain of $96.9 million. The disposed properties had no production or proved reserves.

2015

During the year ended December 31, 2015, the Company sold certain non-strategic properties in various areas for cash proceeds totaling $34.0 million. The proceeds primarily related to the disposition of certain non-producing leasehold acreage in Oklahoma for $25.9 million in May 2015. The Company recognized a pre-tax gain on the transaction of $20.5 million. The disposed properties represented an immaterial portion of the Company's leasehold acreage.

Note 15. Crude Oil and Natural Gas Property Information

The tables reflected below represent consolidated figures for the Company and its subsidiaries. In 2014, the Company initiated exploratory drilling activities in Canada. Through December 31, 2017, those drilling activities have not had a material impact on the Company's total capital expenditures, production, and revenues. Accordingly, the results of operations, costs incurred, and capitalized costs associated with the Canadian operations have not been shown separately from the consolidated figures in the tables below.

The following table sets forth the Company's consolidated results of operations from crude oil and natural gas producing activities for the years ended December 31, 2017, 2016 and 2015.

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Crude oil and natural gas sales | $2,982,966 | $2,026,958 | $2,552,531 |
| Production expenses | (324,214 ) | (289,289 ) | (348,897 ) |
| Production taxes | (208,278 ) | (142,388 ) | (200,637 ) |
| Exploration expenses | (12,393 ) | (16,972 ) | (19,413 ) |
| Depreciation, depletion, amortization and accretion | (1,652,180 ) | (1,679,485 ) | (1,722,336 ) |
| Property impairments | (237,370 ) | (237,292 ) | (402,131 ) |
| Income tax benefit (1) | 504,475 | 126,794 | 33,680 |
| Results from crude oil and natural gas producing activities | $1,053,006 | $(211,674 ) | $(107,203 ) |

(1) Income taxes reflect the application of a combined federal and state tax rate of 38% on pre-tax income and losses generated by operations in the United States. Additionally, the 2017 period includes a $713.7 million income tax benefit recognized upon the Company's remeasurement of its deferred income tax assets and liabilities in response to the enactment of the Tax Reform Act in December 2017. See Note 8. Income Taxes for further discussion.

Costs incurred in crude oil and natural gas activities

Costs incurred, both capitalized and expensed, in connection with the Company's consolidated crude oil and natural gas acquisition, exploration and development activities for the years ended December 31, 2017, 2016 and 2015 are presented below:

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Property acquisition costs: | | | |
| Proved | $8,446 | $5,008 | $557 |
| Unproved | 220,875 | 149,962 | 168,492 |
| Total property acquisition costs | 229,321 | 154,970 | 169,049 |
| Exploration Costs | 123,461 | 182,355 | 241,523 |
| Development Costs | 1,695,954 | 767,148 | 2,148,530 |
| Total | $2,048,736 | $1,104,473 | $2,559,102 |

Costs incurred above include asset retirement costs and revisions thereto of $15.3 million, ($9.6) million and $22.8 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company's consolidated crude oil and natural gas producing activities and related accumulated depreciation, depletion and amortization as of December 31, 2017 and 2016 are as follows:

| | December 31, | |
|---|---|---|
| In thousands | 2017 | 2016 |
| Proved crude oil and natural gas properties | $21,362,199 | $19,802,395 |
| Unproved crude oil and natural gas properties | 365,413 | 429,562 |
| Total | 21,727,612 | 20,231,957 |
| Less accumulated depreciation, depletion and amortization | (8,971,935 ) | (7,553,255 ) |
| Net capitalized costs | $12,755,677 | $12,678,702 |

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling operations are complete, management attempts to determine whether the well has discovered crude oil and natural gas reserves and, if so, whether those reserves can be classified as proved reserves. Often, the determination of whether proved reserves can be recorded under SEC guidelines cannot be made when drilling is completed. In those situations where management believes that economically producible hydrocarbons have not been discovered, the exploratory drilling costs are reflected on the consolidated statements of comprehensive income (loss) as dry hole costs, a component of "Exploration expenses". Where sufficient hydrocarbons have been discovered to justify further exploration or appraisal activities, exploratory drilling costs are deferred under the caption "Net property and equipment" on the consolidated balance sheets pending the outcome of those activities.

On a quarterly basis, operating and financial management review the status of all deferred exploratory drilling costs in light of ongoing exploration activities—in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts. If management determines that future appraisal drilling or development activities are not likely to occur, any associated exploratory well costs are expensed in that period of determination.

The following table presents the amount of capitalized exploratory drilling costs pending evaluation at December 31 for each of the last three years and changes in those amounts during the years then ended:

| | Year ended December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Balance at January 1 | $34,852 | $59,397 | $93,421 |
| Additions to capitalized exploratory well costs pending determination of proved reserves | 79,451 | 123,980 | 132,806 |
| Reclassification to proved crude oil and natural gas properties based on the determination of proved reserves | (81,035 ) | (141,941) | (160,779) |
| Capitalized exploratory well costs charged to expense | (1,912 ) | (6,584 ) | (6,051 ) |
| Balance at December 31 | $31,356 | $34,852 | $59,397 |
| Number of gross wells | 37 | 54 | 73 |

As of December 31, 2017, the Company had no significant exploratory drilling costs that were suspended one year beyond the completion of drilling.

Note 16. Supplemental Crude Oil and Natural Gas Information (Unaudited)

The table below shows estimates of proved reserves prepared by the Company's internal technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company, L.P. prepared reserve estimates for properties comprising approximately 96%, 99%, and 98% of the Company's total proved reserves as of December 31, 2017, 2016, and 2015, respectively. Remaining reserve estimates were prepared by the Company's internal technical staff. All proved reserves stated herein are located in the United States. No proved reserves have been included for the Company's Canadian operations as of December 31, 2017, 2016, and 2015.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate

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expire, unless evidence indicates renewal is reasonably certain. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured, and estimates of engineers other than the Company's might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates may differ significantly from the quantities of crude oil and natural gas ultimately recovered.

Reserves at December 31, 2017, 2016 and 2015 were computed using the 12-month unweighted average of the first-day-of-the-month commodity prices as required by SEC rules.

Natural gas imbalance receivables and payables for each of the three years ended December 31, 2017, 2016 and 2015 were not material and have not been included in the reserve estimates.

Proved crude oil and natural gas reserves

Changes in proved reserves were as follows for the periods presented:

| | Crude Oil (MBbls) | Natural Gas (MMcf) | Total (MBoe) |
|---|---|---|---|
| Proved reserves as of December 31, 2014 | 866,360 | 2,908,386 | 1,351,091 |
| Revisions of previous estimates | (246,840) | (302,143) | (297,198) |
| Extensions, discoveries and other additions | 134,764 | 710,453 | 253,173 |
| Production | (53,517) | (164,454) | (80,926) |
| Sales of minerals in place | (253) | (456) | (329) |
| Purchases of minerals in place | — | — | — |
| Proved reserves as of December 31, 2015 | 700,514 | 3,151,786 | 1,225,811 |
| Revisions of previous estimates | (99,966) | (63,057) | (110,474) |
| Extensions, discoveries and other additions | 97,587 | 911,062 | 249,430 |
| Production | (46,850) | (195,240) | (79,390) |
| Sales of minerals in place | (8,057) | (14,733) | (10,513) |
| Purchases of minerals in place | — | — | — |
| Proved reserves as of December 31, 2016 | 643,228 | 3,789,818 | 1,274,864 |
| Revisions of previous estimates | (77,779) | (25,390) | (82,012) |
| Extensions, discoveries and other additions | 129,895 | 661,867 | 240,206 |
| Production | (50,536) | (228,159) | (88,562) |
| Sales of minerals in place | (4,365) | (64,989) | (15,197) |
| Purchases of minerals in place | 506 | 7,134 | 1,696 |
| Proved reserves as of December 31, 2017 | 640,949 | 4,140,281 | 1,330,995 |

Revisions of previous estimates. Revisions represent changes in previous reserve estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices and differentials, operating costs or development costs.

In 2017, the Company continued to refine its capital program to focus on areas that provide the greatest opportunities to achieve operating efficiencies and cost reductions, to convert undeveloped acreage to acreage held by production, and to improve hydrocarbon recoveries, cash flows and rates of return using optimized completions. As part of this effort, the Company shifted a portion of its 2017 spending away from the SCOOP and Bakken plays to areas in the emerging STACK play that offered more advantageous opportunities and rates of return in the 2017 commodity price environment. This shift in strategy coupled with the Company's increased emphasis on balancing capital spending with cash flows altered the timing and extent of previous development plans in certain areas and resulted in the removal of 41 MMBo and 290 Bcf (totaling 89 MMBoe) of PUD reserves no longer scheduled to be developed within five years from the date of initial booking.

Commodity prices increased on average in 2017 relative to 2016 in response to improving domestic and global supply and demand fundamentals and other factors. The 12-month average first-day-of-the-month price for crude oil increased 20% from $42.75 per Bbl for 2016 to $51.34 per Bbl for 2017, while the 12-month average first-day-of-the-month price for natural gas increased 20% from $2.49 per MMBtu for 2016 to $2.98 per MMBtu for 2017. These changes increased the economic lives of certain producing properties and caused certain previously uneconomic projects to become economic, which had a favorable impact on the Company's proved reserve estimates, resulting in upward revisions of 29 MMBo and 78 Bcf (totaling 42 MMBoe) in 2017.

Additionally, changes in anticipated production performance on certain properties resulted in 59 MMBo of downward revisions to crude oil reserves and 173 Bcf of upward revisions to natural gas reserves (netting to 30 MMBoe of downward revisions) in 2017. Further, changes in ownership interests, operating costs, and other factors during the year resulted in 7 MMBo of downward revisions to crude oil reserves and 11 Bcf of upward revisions to natural gas reserves (netting to 5 MMBoe of downward revisions) in 2017.

Extensions, discoveries and other additions. These are additions to proved reserves resulting from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Extensions, discoveries and other additions for each of the three years reflected in the table above were primarily due to increases in proved reserves associated with our successful drilling and completion activities in the Bakken, SCOOP, and STACK plays. Proved reserve additions in the Bakken totaled 106 MMBo and 253 Bcf (totaling 148 MMBoe) and reserve additions in SCOOP totaled 16 MMBo and 224 Bcf (totaling 53 MMBoe) for the year ended December 31, 2017. Additionally, 2017 extensions and discoveries were impacted by successful drilling and completion results in the STACK play, resulting in proved reserve additions of 8 MMBo and 185 Bcf (totaling 39 MMBoe) in 2017.

Sales of minerals in place. These are reductions to proved reserves resulting from the disposition of properties during a period. See Note 14. Property Dispositions for a discussion of notable dispositions.

Purchases of minerals in place. These are additions to proved reserves resulting from the acquisition of properties during a period. There were no significant acquisitions in the three years reflected in the table above.

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped crude oil and natural gas reserves of the Company as of December 31, 2017, 2016 and 2015:

| | December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Proved Developed Reserves | | | |
| Crude oil (MBbl) | 318,707 | 290,210 | 326,798 |
| Natural Gas (MMcf) | 1,699,161 | 1,370,620 | 1,190,343 |
| Total (MBoe) | 601,901 | 518,646 | 525,188 |
| Proved Undeveloped Reserves | | | |
| Crude oil (MBbl) | 322,242 | 353,018 | 373,716 |
| Natural Gas (MMcf) | 2,441,120 | 2,419,198 | 1,961,443 |
| Total (MBoe) | 729,094 | 756,218 | 700,623 |
| Total Proved Reserves | | | |
| Crude oil (MBbl) | 640,949 | 643,228 | 700,514 |
| Natural Gas (MMcf) | 4,140,281 | 3,789,818 | 3,151,786 |
| Total (MBoe) | 1,330,995 | 1,274,864 | 1,225,811 |

Proved developed reserves are reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves expected to be recovered from new wells on undrilled acreage or from existing wells that require relatively major capital expenditures to recover. Natural gas is converted to barrels of crude oil equivalent using a conversion factor of six thousand cubic feet per barrel of crude oil based on the average equivalent energy content of natural gas compared to crude oil.

Standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves

The standardized measure of discounted future net cash flows presented in the following table was computed using the 12-month unweighted average of the first-day-of-the-month commodity prices, the costs in effect at December 31 of each year and a 10% discount factor. The Company cautions that actual future net cash flows may vary considerably from these estimates. Although the Company's estimates of total proved reserves, development costs and production rates were based on the best available information, the development and production of the crude oil and natural gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, the estimated future net cash flow computations should not be considered to represent the Company's estimate of the expected revenues or the current value of existing proved reserves.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves as of December 31, 2017, 2016 and 2015.

| | December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Future cash inflows | $42,574,897 | $31,008,587 | $36,551,672 |
| Future production costs | (11,159,362 ) | (9,175,410 ) | (10,869,493 ) |
| Future development and abandonment costs | (6,487,097 ) | (6,452,647 ) | (6,935,958 ) |
| Future income taxes (1) | (3,488,755 ) | (3,018,839 ) | (3,717,612 ) |
| Future net cash flows | 21,439,683 | 12,361,691 | 15,028,609 |
| 10% annual discount for estimated timing of cash flows | (10,969,506 ) | (6,851,468 ) | (8,552,325 ) |
| Standardized measure of discounted future net cash flows | $10,470,177 | $5,510,223 | $6,476,284 |

(1) Estimated future income taxes were calculated by applying existing statutory tax rates, including any known future changes, to the estimated pre-tax net cash flows related to proved crude oil and natural gas reserves, giving effect to any permanent taxable differences and tax credits, less the tax basis of the properties involved. The U.S. federal statutory tax rate utilized in estimating future income taxes was 21% at December 31, 2017 and 35% at December 31, 2016 and 2015.

The weighted average crude oil price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $47.03, $35.57, and $41.63 per barrel at December 31, 2017, 2016 and 2015, respectively. The weighted average natural gas price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $3.00, $2.14, and $2.35 per Mcf at December 31, 2017, 2016 and 2015, respectively. Future cash flows are reduced by estimated future costs to develop and produce the proved reserves, as well as certain abandonment costs, based on year-end cost estimates assuming continuation of existing economic conditions. The expected tax benefits to be realized from the utilization of net operating loss carryforwards and tax credits are used in the computation of future income tax cash flows.

The changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves are presented below for each of the past three years.

| | December 31, | | |
|---|---|---|---|
| In thousands | 2017 | 2016 | 2015 |
| Standardized measure of discounted future net cash flows at January 1 | $5,510,223 | $6,476,284 | $18,433,034 |
| Extensions, discoveries and improved recoveries, less related costs | 1,462,629 | 786,587 | 1,091,283 |
| Revisions of previous quantity estimates | (1,004,355 ) | (794,785 ) | (2,156,028 ) |
| Changes in estimated future development and abandonment costs | 743,657 | 1,651,218 | 5,008,731 |
| Sales of minerals in place, net | (41,077 ) | (90,390 ) | (7,768 ) |
| Net change in prices and production costs | 3,808,116 | (2,003,163 ) | (16,111,142 ) |
| Accretion of discount | 665,507 | 798,597 | 1,843,303 |
| Sales of crude oil and natural gas produced, net of production costs | (2,450,474 ) | (1,595,281 ) | (2,002,997 ) |

| | | | |
|---|---|---|---|
| Development costs incurred during the period | 1,045,875 | 454,983 | 1,394,584 |
| Change in timing of estimated future production and other | 948,519 | (538,665) | (3,844,259) |
| Change in income taxes | (218,443) | 364,838 | 2,827,543 |
| Net change | 4,959,954 | (966,061) | (11,956,750) |
| Standardized measure of discounted future net cash flows at December 31 | $10,470,177 | $5,510,223 | $6,476,284 |

Note 17. Quarterly Financial Data (Unaudited)

The Company's unaudited quarterly financial data for 2017 and 2016 is summarized below.

| | Quarter ended | | | |
|---|---|---|---|---|
| In thousands, except per share data | March 31 | June 30 | September 30 | December 31 |
| 2017 | | | | |
| Total revenues (1) | $685,427 | $661,486 | $ 726,743 | $ 1,047,172 |
| Gain on crude oil and natural gas derivatives, net (1) | $46,858 | $28,022 | $ 8,602 | $ 8,165 |
| Property impairments (2) | $51,372 | $123,316 | $ 35,130 | $ 27,552 |
| Litigation settlement (3) | $— | $— | $ — | $ 59,600 |
| Gain (loss) on sale of assets, net (4) | $(3,638) | $780 | $ 3,562 | $ 54,420 |
| Income (loss) from operations | $77,221 | $(29,041) | $ 91,753 | $ 309,468 |
| Net income (loss) (5) | $469 | $(63,557) | $ 10,621 | $ 841,914 |
| Net income (loss) per share: | | | | |
| Basic | $— | $(0.17) | $ 0.03 | $ 2.27 |
| Diluted | $— | $(0.17) | $ 0.03 | $ 2.25 |
| 2016 | | | | |
| Total revenues (1) | $453,174 | $451,211 | $ 526,199 | $ 549,689 |
| Gain (loss) on crude oil and natural gas derivatives, net (1) | $42,112 | $(82,257) | $ 15,668 | $ (47,382) |
| Property impairments (2) | $78,927 | $66,112 | $ 57,689 | $ 34,564 |
| Gain on sale of assets, net (4) | $109 | $96,907 | $ 6,158 | $ 201,315 |
| Income (loss) from operations | $(239,103) | $(110,547) | $ (93,183) | $ 155,299 |
| Loss on extinguishment of debt (6) | $— | $— | $ — | $ 26,055 |
| Net income (loss) | $(198,326) | $(119,402) | $ (109,621) | $ 27,670 |
| Net income (loss) per share: | | | | |
| Basic | $(0.54) | $(0.32) | $ (0.30) | $ 0.07 |
| Diluted | $(0.54) | $(0.32) | $ (0.30) | $ 0.07 |

(1) Gains and losses on crude oil and natural gas derivative instruments are reflected in "Total revenues" on both the consolidated statements of comprehensive income (loss) and this table of unaudited quarterly financial data. Crude oil and natural gas derivative gains and losses have been shown separately to illustrate the fluctuations in revenues that are attributable to the Company's derivative instruments. Commodity price fluctuations each quarter can result in significant swings in mark-to-market gains and losses, which affects comparability between periods.

(2) Property impairments have been shown separately to illustrate the impact on quarterly results attributable to write downs of the Company's assets. Commodity price fluctuations each quarter can result in significant changes in estimated future cash flows and resulting impairments, which affects comparability between periods.

(3) Fourth quarter 2017 results include a $59.6 million pre-tax loss accrual recognized in conjunction with a litigation settlement as discussed in Note 10. Commitments and Contingencies, which resulted in an after-tax decrease in net income of $37.0 million ($0.10 per basic and diluted share).

(4) Gains on asset sales have been shown separately to illustrate the impact on quarterly results attributable to asset dispositions, which differ in significance from period to period and affect comparability. See Note 14. Property Dispositions for a discussion of notable dispositions.

(5) Fourth quarter 2017 results reflect the remeasurement of the Company's deferred income tax assets and liabilities in response to the enactment of the Tax Reform Act in December 2017, which resulted in a one-time decrease in income tax expense and corresponding increase in net income of approximately $713.7 million ($1.92 per basic share and $1.91 per diluted share). See Note 8. Income Taxes for further discussion.

(6) See Note 7. Long-Term Debt for discussion of the loss recognized by the Company upon the redemption of its 2020 Notes and 2021 Notes in the 2016 fourth quarter.

## Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There have been no changes in accountants or any disagreements with accountants.

## Item 9A. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) was performed under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded the Company’s disclosure controls and procedures were effective as of December 31, 2017 to ensure information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and information required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

### Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

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 consolidated 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 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 consolidated 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 consolidated 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, 2017.

The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report that follows.

/s/ Harold G. Hamm
Chairman of the Board and Chief Executive Officer

/s/ John D. Hart
Senior Vice President, Chief Financial Officer and Treasurer

February 21, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2017, and our report dated February 21, 2018 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible 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 an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 21, 2018

## Item 9B. Other Information

None.

# PART III

## Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held in May 2018 (the "Annual Meeting") and is incorporated herein by reference.

## Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

## Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by Item 201(d) of Regulation S-K with respect to securities authorized for issuance under equity compensation plans is disclosed in Part II, Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Equity Compensation Plan Information and is incorporated herein by reference. Other applicable information required as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

## Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

## Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements

The consolidated financial statements of Continental Resources, Inc. and Subsidiaries and the Report of Independent Registered Public Accounting Firm are included in Part II, Item 8 of this report. Reference is made to the accompanying Index to Consolidated Financial Statements.

(2) Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes thereto.

(3) Index to Exhibits

The exhibits required to be filed or furnished pursuant to Item 601 of Regulation S-K are set forth below.

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| 3.1 | Conformed version of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. as amended by amendment filed on June 15, 2015 filed as Exhibit 3.1 to the Company's Form 10-Q for the quarter ended June 30, 2015 (Commission File No. 001-32886) filed August 5, 2015 and incorporated herein by reference. |
| 3.2*** | Third Amended and Restated Bylaws of Continental Resources, Inc. |
| 4.1 | Registration Rights Agreement dated as of May 18, 2007 by and among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust filed as Exhibit 4.1 to the Company's Form 10-Q for the quarter ended March 31, 2017 (Commission File No. 001-32886) filed May 3, 2017 and incorporated herein by reference. |
| 4.2 | Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference. |
| 4.3 | Indenture dated as of March 8, 2012 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.2 to the Company's Form 10-Q for the quarter ended March 31, 2017 (Commission File No. 001-32886) filed May 3, 2017 and incorporated herein by reference. |
| 4.4 | Indenture dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 11, 2013 and incorporated herein by reference. |
| 4.5 | Indenture dated as of May 19, 2014 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2014 and incorporated herein by reference. |
| 4.6*** | Registration Rights Agreement dated as of August 13, 2012 among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, and Jeffrey B. Hume. |
| 4.7 | Indenture dated as of December 8, 2017 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, The Mineral Resources Company and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed December 12, 2017 and incorporated herein by reference. |

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| 4.8 | Registration Rights Agreement dated as of December 8, 2017 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, The Mineral Resources Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as the representative of the several initial purchasers, filed as Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed December 12, 2017 and incorporated herein by reference. |
| 10.1† | Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference. |

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| 10.2† | Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference. |
| 10.3† | Continental Resources, Inc. 2013 Long-Term Incentive Plan included as Appendix A to the Company's Definitive Proxy Statement on Schedule 14A (Commission File No. 001-32886) filed April 10, 2013 and incorporated herein by reference. |
| 10.4† | Form of Employee Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 24, 2013 and incorporated herein by reference. |
| 10.5† | Form of Non-Employee Director Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.3 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 24, 2013 and incorporated herein by reference. |
| 10.6† | Continental Resources, Inc. Deferred Compensation Plan filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed September 26, 2013 and incorporated herein by reference. |
| 10.7† | First Amendment to the Continental Resources, Inc. Deferred Compensation Plan filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2014 (Commission File No. 001-32886) filed May 8, 2014 and incorporated herein by reference. |
| 10.8 | Revolving Credit Agreement dated as of May 16, 2014 among Continental Resources, Inc., as borrower, Banner Pipeline Company L.L.C. and CLR Asset Holdings, LLC, as guarantors, Union Bank, N.A., as administrative agent, and the other lenders party thereto filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 21, 2014 and incorporated herein by reference. |
| 10.9† | Second Amendment to the Continental Resources, Inc. Deferred Compensation Plan adopted and effective as of May 23, 2014 filed as Exhibit 10.15 to the Company's Registration Statement on Form S-4 (Commission File No. 333-196944) filed June 20, 2014 and incorporated herein by reference. |
| 10.10 | Amendment No. 1 dated May 4, 2015 to the Revolving Credit Agreement dated as of May 16, 2014 among Continental Resources, Inc., as borrower, Banner Pipeline Company L.L.C. and CLR Asset Holdings, LLC, as guarantors, the lenders party thereto, and MUFG Union Bank, N.A., as Administrative Agent, filed as Exhibit 10.2 to the Company's Form 10-Q for the quarter ended March 31, 2015 (Commission File No. 001-32886) filed May 6, 2015 and incorporated herein by reference. |
| 10.11† | Summary of Non-Employee Director Compensation Approved as of May 19, 2016 to be effective July 1, 2016 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended June 30, 2016 (Commission File No. 001-32886) filed August 3, 2016 and incorporated herein by reference. |
| 10.12† | Description of cash bonus plan approved as of March 20, 2017 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2017 (Commission File No. 001-32886) filed May 3, 2017 and incorporated herein by reference. |
| 10.13 | |

Purchase Agreement dated as of December 4, 2017 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC, The Mineral Resources Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as the representative of the several initial purchasers, filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed December 5, 2017 and incorporated herein by reference.

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| 21* | Subsidiaries of Continental Resources, Inc. |
| 23.1* | Consent of Grant Thornton LLP. |
| 23.2* | Consent of Ryder Scott Company, L.P. |
| 31.1* | Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241) |
| 31.2* | Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241) |

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| 32** | Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350) |
| 99* | Report of Ryder Scott Company, L.P., Independent Petroleum Engineers and Geologists |
| 101.INS** | XBRL Instance Document |
| 101.SCH** | XBRL Taxonomy Extension Schema Document |
| 101.CAL** | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF** | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB** | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE** | XBRL Taxonomy Extension Presentation Linkbase Document |

*Filed herewith
**Furnished herewith
***Re-filed herewith pursuant to Item 10(d) of Regulation S-K.
† Management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Continental Resources, Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONTINENTAL RESOURCES, INC.

By: /S/ HAROLD G. HAMM
Name: Harold G. Hamm
Title: Chairman of the Board and Chief Executive Officer
Date: February 21, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Continental Resources, Inc. and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ HAROLD G. HAMM<br>Harold G. Hamm | Chairman of the Board and Chief Executive Officer (principal executive officer) | February 21, 2018 |
| /s/ JOHN D. HART<br>John D. Hart | Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer) | February 21, 2018 |
| /s/ WILLIAM B. BERRY<br>William B. Berry | Director | February 21, 2018 |
| /s/ JAMES L. GALLOGLY<br>James L. Gallogly | Director | February 21, 2018 |
| /s/ LON MCCAIN<br>Lon McCain | Director | February 21, 2018 |
| /s/ JOHN T. MCNABB II<br>John T. McNabb II | Director | February 21, 2018 |
| /s/ MARK E. MONROE<br>Mark E. Monroe | Director | February 21, 2018 |