CONTINENTAL RESOURCES, INC
Form 10-K
February 24, 2016

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

FORM 10-K

(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, 2015

or

.. TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 001-32886

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

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 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

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. ¨

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2015 was approximately $4.9 billion, based upon the closing price of $42.39 per share as reported by the New York Stock Exchange on such date.

372,684,421 shares of our $0.01 par value common stock were outstanding on February 16, 2016.

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 2016, 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.

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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.

“ECO-Pad™” A Continental Resources, Inc. trademark which describes a well site layout which allows for drilling multiple wells from a single pad resulting in less environmental impact and lower drilling and completion costs.

“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.
“Mcfe” One thousand cubic feet of natural gas equivalent, with one barrel of crude oil being equivalent to six Mcf of natural gas based on the average equivalent energy content of the two commodities.
“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.
“MMcfe” One million cubic feet of natural gas equivalent, with one barrel of crude oil being equivalent to six Mcf of natural gas based on the average equivalent energy content of the two commodities.
“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 drilling and completion costs. Also may be referred to as ECO-Pad drilling or development.
“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 recompletion.
“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 we use to describe an area of crude oil and liquids-rich natural gas properties located in the Anadarko Basin of Oklahoma in which we operate.
“STACK” Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe properties located in the Anadarko Basin of Oklahoma in which we operate.
“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 enhanced 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,” similar 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;
- 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 or property acquisitions and dispositions;
- 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 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 Kansas and west of the Mississippi River including various plays in the SCOOP (South Central Oklahoma Oil Province), STACK (Sooner Trend Anadarko Canadian Kingfisher), Northwest Cana and Arkoma Woodford areas of Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River with no current drilling or production operations.

We were originally formed in 1967 to explore for, develop and produce crude oil and natural gas properties. Through the late 1980s, our activities and growth remained focused primarily in Oklahoma. In the late 1980s, we expanded our activity into the North region, where a substantial portion of our operations is now concentrated due to our successful leasing and drilling activities in the Bakken field. The North region comprised approximately 68% of our crude oil and natural gas production and approximately 77% of our crude oil and natural gas revenues for the year ended December 31, 2015. Approximately 58% of our estimated proved reserves as of December 31, 2015 are located in the North region. In recent years, we have significantly expanded our activity in our South region resulting from our discovery of the SCOOP play and our increased activity in the Northwest Cana and STACK plays, all of which are located in Oklahoma. Our South region comprised approximately 32% of our crude oil and natural gas production, 23% of our crude oil and natural gas revenues, and 42% of our estimated proved reserves as of and for the year ended December 31, 2015.

We have focused our operations on the exploration and development of crude oil since the 1980s. For the year ended December 31, 2015, crude oil accounted for approximately 66% of our total production and approximately 85% of our crude oil and natural gas revenues. Crude oil represents approximately 57% of our estimated proved reserves as of December 31, 2015.

We focus our exploration activities in large new or developing crude oil and liquids-rich 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, 2015, our estimated proved reserves were 1,226 MMBoe, with estimated proved developed reserves of 525 MMBoe, or 43% of our total estimated proved reserves. For the year ended December 31, 2015, we generated crude oil and natural gas revenues of $2.6 billion and operating cash flows of $1.9 billion. For the year ended December 31, 2015, production averaged 221,715 Boe per day, a 27% increase over average production of 174,189 Boe per day for the year ended December 31, 2014. Average daily production for the quarter ended December 31, 2015 increased 16% to 224,936 Boe per day from 193,456 Boe per day for the quarter ended December 31, 2014.

The table below summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2015, average daily production for the quarter ended December 31, 2015 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 of this report for further discussion of uncertainties inherent in the reserve estimates.

	December 31, 2015						
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (In millions)	Net producing wells	Average daily production for fourth quarter 2015 (Boe per day)	Percent of total	Annualized reserve/production index (2)
North Region:							
Bakken field							
North Dakota Bakken	618,197	50.4 %	$ 4,005	1,196	125,583	55.8 %	13.5
Montana Bakken	44,837	3.6 %	431	273	10,772	4.8 %	11.4
Red River units							
Cedar Hills	42,456	3.5 %	523	132	8,658	3.9 %	13.4
Other Red River units	5,603	0.5 %	34	120	2,996	1.3 %	5.1
Other	2,271	0.2 %	20	8	902	0.4 %	6.9
South Region:							
SCOOP	412,546	33.7 %	2,508	220	64,534	28.7 %	17.5
Northwest Cana/STACK	83,951	6.8 %	378	67	7,709	3.4 %	29.8
Arkoma Woodford	9,912	0.8 %	49	56	2,124	0.9 %	12.8
Other	6,038	0.5 %	38	232	1,658	0.8 %	10.0
Total	1,225,811	100.0 %	$ 7,986	2,304	224,936	100.0 %	14.9

(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 $1.5 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.

(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 2015 production into estimated proved reserve volumes as of December 31, 2015.

Industry Operating Environment and Outlook

Crude oil prices remained significantly depressed in 2015 and face continued downward pressure due to domestic and global supply and demand factors. The downward price pressure intensified in late 2015 and early 2016, with crude oil prices dropping below $27 per barrel in February 2016, a level not seen since 2003. Natural gas prices faced similar downward pressure in 2015, dropping below $1.70 per MMBtu in December 2015.

In response to these price declines, and given the uncertainty regarding the timing and magnitude of any price recovery, we have significantly reduced our planned non-acquisition capital spending for 2016 to $920 million, a reduction of 63% compared to $2.50 billion of non-acquisition capital spending in 2015. This non-acquisition investment level is designed to target capital expenditures and cash flows being relatively balanced for 2016 at an assumed average West Texas Intermediate benchmark crude oil price of approximately $37 per barrel for the year, with any cash flow deficiencies being funded by borrowings under our revolving credit facility. Our reduced spending is projected to result in a decrease in our 2016 average daily production of approximately 10% compared to 2015. With reduced capital spending planned for 2016, we will be growing our drilled but uncompleted ("DUC") well inventory. Our DUC inventory in North Dakota is expected to increase from 135 gross operated wells at December 31, 2015 to approximately 195 gross operated wells at year-end 2016. Our DUC inventory in Oklahoma is expected to increase from 35 gross operated wells at December 31, 2015 to approximately 50 gross operated wells at year-end 2016. We will continue to monitor our capital spending closely based on actual and projected cash flows and could make additional reductions to our 2016 capital spending should commodity prices decrease further. Conversely, a significant improvement in commodity prices could result in an increase in our capital expenditures.

In light of the challenges facing our industry, our primary business strategies for 2016 will include: (1) optimizing cash flows through operating efficiencies and cost reductions, (2) high-grading investments based on rates of return and opportunities to convert undeveloped acreage to acreage held by production, and (3) working to balance capital spending with cash flows to minimize new borrowings and maintain ample liquidity, as elaborated upon in the subsequent section titled Our Business Strategy.

See the section below titled Summary of Crude Oil and Natural Gas Properties and Projects for further discussion of our 2016 plans. Also see Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for discussion of our 2015 operating results and potential impact on 2016 operating results due to depressed commodity prices.

Our Business Strategy

Despite a reduced capital budget for 2016 that is reflective of the current commodity price environment, 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 high rate-of-return projects. We hold a portfolio of leasehold acreage and drilling opportunities in certain premier U.S. resource plays with varying exposure 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 convert undeveloped acreage to acreage held by production and to maximize hydrocarbon recoveries and rates of return on capital employed. Our operations are primarily focused on the exploration and development of crude oil, but we also allocate capital to liquids-rich natural gas areas that provide attractive rates of return.

Optimizing cash flows through operating efficiencies, cost reductions, and enhanced completions. We continue to manage through the current commodity price downturn 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 majority 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.

In 2015, we achieved large efficiency gains in various aspects of our business, including reductions in spud-to-total depth drilling times and average days to drill horizontal laterals, which translated into substantial reductions in drilling costs in our core areas. Our drilling and completion costs for most operated wells declined on average approximately 25% in 2015 due to operational efficiency gains and lower service costs. In addition to lowering our drilling and completion costs, we also optimize cash flows through the use of enhanced completion technologies. In North Dakota, we are optimizing cash flows through enhanced completions using new hybrid and slickwater designs, which have increased 90-day production rates between 35% and 50% on average. In Oklahoma, we are optimizing cash flows using enhanced completions that target optimum sand and fluid combinations. Initial results from our 2015 activities are encouraging, and we expect most of our 2016 well completions in Oklahoma will use enhanced completion methods.

Maintaining financial flexibility and a strong balance sheet. Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2016, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2016 capital budget is reflective of decreased commodity prices and 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. As we have done historically to preserve or enhance liquidity we may adjust our capital program throughout the year, divest non-strategic assets, or enter into strategic joint ventures.

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 best exploit our extensive inventory of repeatable drilling opportunities to achieve attractive rates of return. From January 1, 2011 through December 31, 2015, our proved reserve additions through organic extensions and discoveries were 1,534 MMBoe compared to 86 MMBoe of proved reserve acquisitions during that same period.

Our Business Strengths

We have a number of strengths to help us manage through the current commodity price downturn and execute our business strategy, including the following:

Large Acreage Inventory. We held approximately 1.19 million net undeveloped acres and 1.15 million net developed acres under lease in certain premier U.S. resource plays as of December 31, 2015. Approximately 59% of our net undeveloped acres are located within unconventional resource plays in the Bakken, SCOOP, Northwest Cana, STACK and Arkoma Woodford areas. We have developed sizable acreage positions in our core operating areas and believe the concentration of our assets allows us to achieve operating efficiencies and reduce costs through economies of scale. We are among the largest leaseholders in the Bakken and SCOOP plays with approximately 1.05 million net acres and 439,800 net acres under lease in those respective plays at December 31, 2015. Being an early entrant in the Bakken and SCOOP plays has allowed us to capture significant acreage positions in core parts of the plays.

Expertise with Horizontal Drilling and Enhanced Completion Methods. We have substantial experience with horizontal drilling and enhanced completion methods and continue to be among the industry leaders in the use of new drilling and completion technologies. We continue to optimize drilling and completion efficiencies through the use of multi-well pad drilling in our operating areas. Further, we are among industry leaders in extending lateral drilling lengths. Results to date indicate longer laterals have a positive impact on well productivity and economics. We have also been among industry leaders in testing enhanced completion technologies involving various combinations of fluid types, proppant types and volumes, and stimulation stage lengths to determine optimal methods for maximizing crude oil 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, 2015, we operated properties comprising 87% of our total proved reserves and 83% of our PV-10. 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 34 years of oil and gas industry experience.

Financial Position and Liquidity. We have a revolving credit facility with lender commitments totaling $2.75 billion which may be increased up to a total of $4.0 billion upon agreement with participating lenders to provide additional liquidity if needed to take advantage of business opportunities and fund our capital program and commitments. We had approximately $1.9 billion of available borrowing capacity under our credit facility at February 19, 2016 after considering outstanding borrowings and letters of credit. We have no near-term debt maturities, with our earliest maturity being a $500 million term loan due in November 2018.

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.

In November 2015, we completed transactions that increased our lender commitments under our revolving credit facility and refinanced a portion of our credit facility borrowings to an unsecured three-year term loan with a lower interest rate. These transactions enhanced our liquidity and reduced our interest expense.

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 and production data, seismic data and well test data.

The following table sets forth our estimated proved crude oil and natural gas reserves and PV-10 by reserve category as of December 31, 2015. The total Standardized Measure of discounted cash flows as of December 31, 2015 is also presented. Our reserve estimates as of December 31, 2015 are based primarily on a reserve report prepared by Ryder Scott. In preparing its report, Ryder Scott evaluated properties representing approximately 99% of our PV-10, 99% of our proved crude oil reserves, and 97% of our proved natural gas reserves as of December 31, 2015. 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, PV-10 and Standardized Measure at December 31, 2015 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2015 through December 2015, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $50.28 per Bbl for crude oil and $2.58 per MMBtu for natural gas ($41.63 per Bbl for crude oil and $2.35 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	324,631	1,178,434	521,037	$5,678.6
Proved developed non-producing	2,167	11,909	4,151	29.0
Proved undeveloped	373,716	1,961,443	700,623	2,278.4
Total proved reserves	700,514	3,151,786	1,225,811	$7,986.0
Standardized Measure (1)				$6,476.3

(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 $1.5 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.

The following table provides additional information regarding our estimated proved crude oil and natural gas reserves by region as of December 31, 2015.

	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	211,358	366,248	272,399	269,994	454,819	345,797
Montana Bakken	26,744	31,323	31,964	11,250	9,732	12,872
Red River units						
Cedar Hills	41,628	4,967	42,456	—	—	—
Other Red River units	5,039	3,386	5,603	—	—	—
Other	253	12,109	2,271	—	—	—
South Region:						
SCOOP	37,516	575,754	133,475	73,442	1,233,778	279,072
Northwest Cana/STACK	2,736	109,999	21,070	19,030	263,114	62,882
Arkoma Woodford	11	59,404	9,912	—	—	—
Other	1,513	27,153	6,038	—	—	—
Total	326,798	1,190,343	525,188	373,716	1,961,443	700,623

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

	Year Ended December 31,		
MBoe	2015	2014	2013
Proved reserves at beginning of year	1,351,091	1,084,125	784,677
Revisions of previous estimates	(297,198)	(107,949)	(96,054)
Extensions, discoveries and other additions	253,173	440,621	444,654
Production	(80,926)	(63,579)	(49,610)
Sales of minerals in place	(329)	(3,227)	—
Purchases of minerals in place	—	1,100	458
Proved reserves at end of year	1,225,811	1,351,091	1,084,125

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, operating costs, or development costs. Commodity prices decreased significantly in 2015. The 12-month average price for crude oil decreased 47% from $94.99 per Bbl for 2014 to $50.28 per Bbl for 2015, while the 12-month average price for natural gas decreased 41% from $4.35 per MMBtu for 2014 to $2.58 per MMBtu for 2015. These decreases shortened the economic lives of certain producing properties and caused certain exploration and development projects to become uneconomic which had an adverse impact on our proved reserve estimates, resulting in downward reserve revisions of 185 MMBo and 391 Bcf (totaling 251 MMBoe) in 2015. We may experience additional downward reserve revisions as a result of prices in 2016 if the currently depressed price environment for crude oil and natural gas persists or worsens.

In response to the continued decrease in commodity prices throughout 2015, we have further refined our drilling program and reduced our planned rig count to concentrate our efforts in our core areas of North Dakota and Oklahoma that provide the best opportunities to improve recoveries and rates of return. The refinement of our drilling program contributed to the removal of PUD reserves no longer scheduled to be developed within five years from the date in which they were first booked. One factor leading to the removal is an increased emphasis on multi-well pad drilling in the Bakken, which resulted in the removal of PUDs in certain areas in favor of PUDs more likely to be developed with pad drilling where operating efficiencies may be realized. Further, in the SCOOP play we removed certain PUD locations originally planned to be developed with standard lateral drilling lengths in favor of PUDs to be developed with extended length laterals in similar locations. Longer laterals are believed to have a positive impact on well productivity and economics. The combination of these and other factors resulted in the removal of 65 MMBo and 197 Bcf (totaling 98 MMBoe) of PUD reserves in 2015. These removals do not necessarily 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 a favorable change in commodity prices and an expansion of our capital expenditure budget.

Additionally, changes in anticipated production performance on certain properties resulted in 63 MMBo of downward revisions to crude oil proved reserves and 125 Bcf of upward revisions to natural gas proved reserves (netting to 42 MMBoe of downward revisions) in 2015.

The downward revisions described above were partially offset by upward revisions in 2015 due to lower operating costs being realized in conjunction with depressed commodity prices and improvements in operating efficiencies as well as other factors.

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 activity in the Bakken field and SCOOP play. Proved reserve additions from our drilling activities in the Bakken totaled 96 MMBoe, 222 MMBoe and 276 MMBoe for 2015, 2014 and 2013, respectively, while reserve additions in SCOOP totaled 93 MMBoe, 208 MMBoe and 158 MMBoe for 2015, 2014 and 2013, respectively. Additionally, extensions and discoveries in 2015 were significantly impacted by successful drilling results in the Northwest Cana/STACK area, resulting in proved reserve additions of 57 MMBoe in 2015. See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2015 drilling activities. We expect a significant portion of future reserve additions will come from our major development projects in the Bakken, SCOOP, and Northwest Cana/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 mineral purchases 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, 2015 are located in the Bakken, SCOOP, and Northwest Cana/STACK plays, our most active development areas, with those plays comprising 51%, 40%, and 9%, respectively, of our total PUD reserves at year-end 2015. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2015. Our PUD reserves at December 31, 2015 include 91 MMBoe of reserves associated with operated drilled but uncompleted wells.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves at December 31, 2014	524,223	1,946,335	848,612
Revisions of previous estimates	(216,289)	(315,390)	(268,855)
Extensions and discoveries	111,058	546,854	202,201
Sales of minerals in place	(63)	(80)	(76)
Purchases of minerals in place	—	—	—
Conversion to proved developed reserves	(45,213)	(216,276)	(81,259)
Proved undeveloped reserves at December 31, 2015	373,716	1,961,443	700,623

Revisions of previous estimates. During the year ended December 31, 2015, we removed 1,225 gross (689 net) PUD locations, which resulted in the removal of 65 MMBo and 197 Bcf (totaling 98 MMBoe) of PUD reserves. These removals were due to the continued decrease in commodity prices during 2015, particularly in late 2015, and resulting refinement of our drilling program to place greater emphasis on core areas of the Bakken, SCOOP and Northwest Cana/STACK areas that provide the best opportunities to improve recoveries and rates of return, with increased focus on areas capable of being developed through the use of multi-well pad drilling and extended length laterals. These and other factors contributed to the removal of PUD

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reserves in certain areas having less attractive rates of return, are less likely to be developed using pad drilling or extended laterals, or are otherwise no longer scheduled to be developed within five years of the date in which they were initially booked.

Also as a result of decreased commodity prices, certain exploration and development projects became uneconomic which had an adverse impact on our PUD reserve estimates, resulting in downward revisions of 131 MMBo and 301 Bcf (totaling 181 MMBoe) in 2015.

Additionally, changes in anticipated production performance on producing properties having offsetting PUD locations resulted in 46 MMBo of downward revisions to crude oil PUD reserves and 121 Bcf of upward revisions to natural gas PUD reserves (netting to 26 MMBoe of downward revisions) in 2015.

The downward revisions described above were partially offset by upward revisions in 2015 due to lower operating costs being realized on producing properties having offsetting PUD locations in conjunction with depressed commodity prices and improvements in operating efficiencies as well as other factors.

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 Northwest Cana/STACK areas. PUD reserve additions in the Bakken totaled 65 MMBo and 109 Bcf (totaling 83 MMBoe) in 2015, SCOOP PUD reserve additions totaled 28 MMBo and 248 Bcf (totaling 69 MMBoe), and Northwest Cana/STACK PUD reserve additions totaled 19 MMBo and 190 Bcf (totaling 50 MMBoe). See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2015 drilling activities in these areas.

Conversion to proved developed reserves. In 2015, we developed approximately 18% of our PUD locations and 10% of our PUD reserves booked as of December 31, 2014 through the drilling of 526 gross (165 net) development wells at an aggregate capital cost of approximately $1.0 billion. In the second half of 2015, we accelerated the reduction of our capital spending and well completion activities in response to the continued decrease in commodity prices, which resulted in our 2015 capital spending being approximately $200 million below budget. These actions adversely impacted our conversion of PUD reserves to proved developed reserves during the year.

Development plans. We have acquired substantial leasehold positions in the Bakken, SCOOP and Northwest Cana/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. Going forward, while we may opportunistically drill strategic exploratory wells, the majority of our capital expenditures will be focused on developing our PUD locations given the current commodity price environment. Estimated future development costs relating to the development of PUD reserves are projected to be approximately $0.8 billion in 2016, $0.9 billion in 2017, $1.4 billion in 2018, $2.0 billion in 2019, and $1.4 billion in 2020. These capital expenditure projections are reflective of the significant decrease in commodity prices during the year and have been established based on an expectation of available cash flows and availability under our revolving credit facility. Development of our existing PUD reserves at December 31, 2015 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 depressed commodity prices or for other reasons have been removed from our reserves at December 31, 2015. We had no PUD reserves at December 31, 2015 that remained 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, 99% of our PV-10, 99% of our proved crude oil reserves, and 97% of our proved natural gas reserves as of December 31, 2015 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 reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. In the fourth quarter, 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 reserve estimates. Proved reserve 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 reserve report and on a semi-annual basis review any internally estimated significant changes to our proved reserves.

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 31 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 President and Chief Operating Officer. The reserve estimates are reviewed and approved by the President and Chief Operating Officer and certain other members of senior management.

Proved Reserve and PV-10 Sensitivities

Our year-end 2015 proved reserve and PV-10 estimates were prepared using 2015 average prices of $50.28 per Bbl for crude oil and $2.58 per MMBtu for natural gas. Commodity prices existing in February 2016 are lower than the 2015 average prices. If commodity prices do not increase from current levels, our future calculations of estimated proved reserves and PV-10 will be based on lower prices which could result in the removal of then uneconomic reserves from our proved reserves in future periods.

Provided below are sensitivities illustrating the potential impact on our estimated proved reserves and PV-10 at December 31, 2015 under different pricing 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 are only meant to demonstrate the impact that changing commodity prices may have on estimated proved reserves 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 and PV-10 under various crude oil price scenarios, with natural gas prices being held constant at the 2015 average price of $2.58 per MMBtu.

The natural gas price sensitivities provided below show the impact on proved reserves and PV-10 under various natural gas price scenarios, with crude oil prices being held constant at the 2015 average price of $50.28 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, 2015:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	1,053,294	595,396	318,341	205,227	1,371,635	800,623
Montana Bakken	188,424	148,764	154,017	96,049	342,441	244,813
Red River units	158,700	138,716	43,082	26,407	201,782	165,123
Other	17,957	5,731	246,076	202,615	264,033	208,346
South Region:						
SCOOP	192,863	115,513	578,470	324,307	771,333	439,820
Northwest Cana/STACK (1)	129,163	79,762	138,537	75,459	267,700	155,221
Arkoma Woodford	110,560	26,240	3,388	173	113,948	26,413
Other	80,796	44,281	112,280	60,626	193,076	104,907
East Region	—	—	224,142	204,012	224,142	204,012
Total	1,931,757	1,154,403	1,818,333	1,194,875	3,750,090	2,349,278

(1) Represents acreage available for drilling in the Woodford formation (Northwest Cana) and the Meramec and Osage formations (STACK) overlying the Woodford. Included in this acreage are 38,600 total net acres of Woodford drilling rights in an area of mutual interest established under our Northwest Cana joint development agreement.

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2015 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.

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	158,625	92,105	76,643	53,665	25,417	17,474
Montana Bakken	71,649	43,457	52,822	34,576	14,436	9,567
Red River units	13,800	10,190	5,319	3,227	4,931	3,444
Other	13,103	5,879	639	256	17,225	17,129
South Region:						
SCOOP	207,054	110,529	172,890	104,626	47,703	37,209
Northwest Cana/STACK	36,069	23,657	29,196	15,202	44,087	25,819
Arkoma Woodford	—	—	—	—	—	—
Other	48,716	30,052	40,946	19,198	3,834	1,702
East Region	4,688	4,319	60,795	52,840	45	134
Total	553,704	320,188	439,250	283,590	157,678	112,478

Drilling Activity

During the three years ended December 31, 2015, we drilled and completed exploratory and development wells as set forth in the table below:

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	28	19.8	94	70.5	75	51.5
Natural gas	19	1.4	42	8.3	40	23.7
Dry holes	1	1.0	3	1.6	3	2.1
Total exploratory wells	48	22.2	139	80.4	118	77.3
Development wells:						
Crude oil	707	215.5	897	290.3	734	250.9
Natural gas	142	32.8	64	16.8	26	5.4
Dry holes	—	—	1	1.0	—	—
Total development wells	849	248.3	962	308.1	760	256.3
Total wells	897	270.5	1,101	388.5	878	333.6

As of December 31, 2015, there were 417 gross (178 net) operated and non-operated wells that have been spud and are in the process of drilling, completing or waiting on completion.

For 2016, we plan to operate an average of approximately 19 drilling rigs for the year. Our rig activity for 2016 will depend on crude oil and natural gas prices and potential drilling efficiency gains and, accordingly, our rig count may increase or decrease from planned levels. As a result of the significant decrease in commodity prices, the number of providers of materials and services has decreased in the regions where we operate. As a result, the likelihood of experiencing shortages of materials and services may be increased in connection with any period of commodity price recovery. See Part I, Item 1A. Risk Factors—The unavailability or high cost of drilling rigs, 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.

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 2016 in our key operating areas. Our 2016 capital budget is reflective of the depressed commodity price environment and has been established based on an expectation of available cash flows. If cash flows are materially impacted by a further 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 2016 budgeted capital expenditures by operating area.

	2016 Plan		
	Gross wells planned for completion (1)	Net wells planned for completion (1)	Capital expenditures (in millions)
North Region:			
North Dakota Bakken	127	26	$320
South Region:			
SCOOP	113	25	260
Northwest Cana	28	11	62
STACK	15	9	142
Total exploration and development drilling	283	71	$784
Land			78
Capital facilities, workovers and other corporate assets			55
Seismic			3
Total 2016 capital budget, excluding acquisitions			$920

(1) Represents wells expected to be drilled, completed, and producing in 2016 and excludes an expected increase in our drilled but uncompleted well inventory of 75 gross (47 net) wells during the year.

North Region

Our properties in the North region represented 63% of our PV-10 as of December 31, 2015 and 66% of our average daily Boe production for the fourth quarter of 2015. Our average daily production from such properties was 148,911 Boe per day for the fourth quarter of 2015, an increase of 3% over the comparable 2014 period. Our principal producing properties in the North region are located in the Bakken field and the Red River units.

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, 2015, we controlled one of the largest leasehold positions in the Bakken with approximately 1.71 million gross (1.05 million net) acres under lease.

Our total Bakken production averaged 136,355 Boe per day during the fourth quarter of 2015, up 4% from the 2014 fourth quarter due to additional drilling and completion activity. Despite depressed commodity prices in 2015, we continued to make progress with our Bakken drilling program during the year which was almost entirely focused in North Dakota. Our 2015 drilling activity in North Dakota focused on the continued development of de-risked, higher rate-of-return areas in core parts of the play and the testing of various enhanced completion technologies to determine optimal methods for maximizing crude oil recoveries and rates of return.

In 2015, we completed 650 gross (181 net) wells in the Bakken. Our Bakken properties represented 56% of our PV-10 at December 31, 2015 and 61% of our average daily Boe production for the 2015 fourth quarter. Our total proved Bakken field reserves as of December 31, 2015 were 663 MMBoe, which represents a decrease of 23% compared to December 31, 2014 due in part to downward reserve revisions in 2015 prompted by lower commodity prices and changes in drilling plans. Our inventory of proved undeveloped locations totaled 1,292 gross (705 net) wells as of December 31, 2015.

As of December 31, 2015, we operated eight rigs in the Bakken, all in North Dakota, which we subsequently decreased to four operated rigs in early 2016. We plan to average approximately four operated rigs in North Dakota Bakken throughout 2016. We plan to operate fewer rigs in North Dakota Bakken in 2016 compared to 2015 as part of our efforts to align our 2016 capital expenditures with cash flows in response to the continued decrease in crude oil prices in late 2015 and early 2016.

In 2016, we plan to invest approximately $320 million to drill, complete and initiate production on 127 gross (26 net) wells in North Dakota Bakken. Our 2016 drilling program will focus on drilling de-risked acreage in core parts of the play that provide opportunities for converting undeveloped acreage to acreage held by production, increasing capital efficiency, reducing finding and development costs, and maximizing rates of return.

Red River Units

The Red River units are comprised of nine units located along the Cedar Creek Anticline in North Dakota, South Dakota and Montana that produce crude oil and natural gas from the Red River "B" formation. Our principal producing properties in the Red River units include the Cedar Hills units in North Dakota and Montana, the Medicine Pole Hills units in North Dakota, and the Buffalo Red River units in South Dakota. Our properties in the Red River units comprise a portion of the Cedar Hills field.

All combined, our Red River units and adjacent areas represented 7% of our PV-10 as of December 31, 2015 and 5% of our average daily Boe production for the fourth quarter of 2015. Our average daily production from these legacy properties decreased 12% in the fourth quarter of 2015 compared to the fourth quarter of 2014 due to natural declines in production and reduced drilling activity. We undertook limited drilling activity in the Red River units in 2015, choosing instead to allocate capital to areas in North Dakota Bakken and Oklahoma that generate more attractive rates of return. For 2016, we plan to invest approximately $8 million in the Red River units primarily on well workover activities aimed at enhancing production and recoveries for these legacy properties.

North Region Marketing Activities

Crude Oil. We utilize a portfolio approach (rail and pipe) to market our crude oil that began in 2008 with our first shipments of crude oil by rail out of the Williston Basin. Accessing new pipeline transportation optionality that came online in 2015, we shifted a significant portion of our crude oil from rail transportation to pipeline transportation during the year. We plan to continue with a portfolio approach to reach the optimum markets in an effort to maximize wellhead value for our crude oil production.

Natural Gas. Field infrastructure build-out continued in the Williston Basin in 2015 as third party midstream gathering and processing companies expanded field gathering and compression facilities, cryogenic processing capacity and natural gas liquids ("NGL") pipeline and rail capacity to market centers. In 2015, we continued to be a leader in minimizing natural gas flaring in North Dakota. For the year ended December 31, 2015, we delivered approximately 87% of our operated natural gas production in North Dakota Bakken to market, flaring approximately 13% compared to an average of 18% flared by industry peers operating in the play.

South Region

Our properties in the South region represented 37% of our PV-10 as of December 31, 2015 and 34% of our average daily Boe production for the fourth quarter of 2015. For the 2015 fourth quarter, our average daily production from such properties was 76,025 Boe per day, an increase of 56% from the comparable period in 2014. Our principal producing properties in the South region are located in the SCOOP, Northwest Cana 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. 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 2014, our drilling activities resulted in the vertical expansion of our SCOOP position and discovery of the Springer formation, which is located approximately 1,000 to 1,500 feet above the Woodford formation. Located in the heart of our SCOOP acreage, our Springer position supplements our Woodford leasehold and expands our resource potential and inventory in the play. Our 2015 drilling activity in SCOOP focused on expanding the known productive extents of the SCOOP Woodford and SCOOP Springer formations and continued development of de-risked, higher rate-of-return areas in core parts of the play. Also, in 2015 we began operation of water recycling facilities in the SCOOP area that economically reuse stimulation water for both operational efficiencies and environmental benefits.

We are a leading producer, leasehold owner and operator in the SCOOP play. As of December 31, 2015, we controlled one of the largest leasehold positions in SCOOP with approximately 771,300 gross (439,800 net) acres under lease. SCOOP represented 31% of our PV-10 as of December 31, 2015 and 29% of our average daily Boe production for the fourth quarter of 2015. For the year ended December 31, 2015, SCOOP production grew 75% over 2014 due to the continued success of our drilling activity in the play. We completed 204 gross (74 net) wells in SCOOP during 2015. Proved reserves increased 12% year-over-year to 413 MMBoe as of December 31, 2015, of which 32% represents proved developed reserves. Our inventory of proved undeveloped drilling locations in SCOOP as of December 31, 2015 totaled 370 gross (224 net) wells.

In 2016, we plan to invest approximately $260 million to drill, complete and initiate production on 113 gross (25 net) wells in the SCOOP play. Our 2016 drilling program will continue to focus on expanding the known productive extents of the SCOOP Woodford and SCOOP Springer formations and de-risking our acreage, 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 maximizing rates of return. As of December 31, 2015, we had six operated rigs drilling in the SCOOP play and plan to average approximately five to six operated rigs throughout 2016.

Northwest Cana and STACK

Our Northwest Cana properties are located primarily in Blaine, Dewey and Custer Counties of Oklahoma and primarily target the Woodford formation. 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 significant portion of our Northwest Cana natural gas properties, primarily in Blaine and Dewey counties. Under the agreement, SK has committed to fund, or carry, 50% of our share of certain future drilling and completion costs through September 2019, which has enabled us to generate favorable economics and value from previously idle properties in Northwest Cana. As of December 31, 2015, we had five operated rigs drilling in Northwest Cana and plan to average approximately five operated rigs throughout 2016 to capitalize on the favorable economics provided by our joint development agreement with SK. In 2016, we plan to invest approximately $62 million to drill, complete and initiate production on 28 gross (11 net) wells in Northwest Cana within the area of mutual interest with SK.

In 2015, we added the STACK play to our portfolio of assets through our leasing and drilling efforts. STACK, an acronym for Sooner Trend Anadarko Canadian Kingfisher, is a significant new resource play located in the Anadarko Basin of Oklahoma characterized by stacked geologic formations with major targets in the Meramec and Osage formations overlying the Woodford formation. 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. Our drilling in STACK is in the early stages and production has just recently begun to grow. We anticipate the economics from our STACK properties will compare favorably with our SCOOP and North Dakota Bakken assets and will provide value-added opportunities for the Company. As of December 31, 2015, we had four operated rigs drilling in STACK and we plan to average approximately four to five operated rigs throughout 2016. In 2016, we plan to invest approximately $142 million to drill, complete and initiate production on 15 gross (9 net) wells in STACK. Our 2016 activities will be focused on delineating and de-risking our acreage, monitoring production, and further developing our geologic and economic models in the area.

Combined, our Northwest Cana and STACK properties represented 5% of our PV-10 as of December 31, 2015 and 3% of our average daily Boe production for the fourth quarter of 2015. As of December 31, 2015, we held a total of 155,221 net acres under lease in Northwest Cana and STACK, representing acreage available for drilling in the Woodford formation (Northwest Cana) and the Meramec and Osage formations (STACK) overlying the Woodford and inclusive of 38,600 total net acres of Woodford drilling rights in the area of mutual interest established under our Northwest Cana joint development agreement with SK.

Combined production in Northwest Cana and STACK increased to an average rate of 7,709 Boe per day during the fourth quarter of 2015, up 104% over the 2014 fourth quarter due to additional drilling and completion activity resulting from our drilling program. We completed a combined 26 gross (10 net) wells in Northwest Cana and STACK during 2015. Proved reserves totaled 84 MMBoe as of December 31, 2015, of which 25% represents proved developed reserves. Our combined inventory of proved undeveloped locations stood at 198 gross (66 net) wells as of December 31, 2015.

South Region Marketing Activities

Crude Oil. Our South region production is located in relatively close proximity to regional refineries as well as the crude oil trading hub located in Cushing, Oklahoma. Because of this close proximity to local markets as well as Cushing, we are able to market our South region production with the intent of capturing the best market prices available depending on the crude oil grade and location. We use the competition among refineries, midstream companies, and bulk traders in an effort to maximize wellhead value for our crude oil production.

Natural Gas. In 2015, field infrastructure build-out continued at a rapid pace in the Anadarko Basin and in SCOOP as third party midstream gathering and processing companies expanded field gathering and compression facilities, cryogenic processing capacity and NGL pipeline capacity to market centers. On January 1, 2016 a third party placed a new lateral into service that connects to an existing plant which provides a connection to an interstate pipeline system for sales to downstream customers.

Throughout our South region leasehold, we are coordinating our well completion operations to coincide with well connections to gathering systems in order to minimize greenhouse gas emissions. We continue to assess downstream transportation options and have developed relationships with downstream transport and end-use customers for possible future portfolio pricing benefits.

Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2015, 2014 and 2013 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2015:

	Year ended December 31,		
	2015	2014	2013
Net production volumes:			
Crude oil (MBbls) (1)			
North Dakota Bakken	37,539	30,917	23,513
SCOOP	7,198	3,652	2,004
Total Company	53,517	44,530	34,989
Natural gas (MMcf)			
North Dakota Bakken	47,425	33,610	26,783
SCOOP	91,687	55,017	29,438
Total Company	164,454	114,295	87,730
Crude oil equivalents (MBoe)			
North Dakota Bakken	45,444	36,518	27,977
SCOOP	22,479	12,822	6,910
Total Company	80,926	63,579	49,610
Average sales prices: (2)			
Crude oil ($/Bbl)			
North Dakota Bakken	$39.76	$80.22	$89.45
SCOOP	43.98	87.58	95.63
Total Company	40.50	81.26	89.93
Natural gas ($/Mcf)			
North Dakota Bakken	$2.34	$6.63	$5.94
SCOOP	2.39	5.23	5.25
Total Company	2.31	5.40	4.87
Crude oil equivalents ($/Boe)			
North Dakota Bakken	$35.29	$73.96	$80.87
SCOOP	23.81	47.35	50.08
Total Company	31.48	66.53	72.04
Average costs per Boe: (2)			
Production expenses ($/Boe)			
North Dakota Bakken	$4.79	$5.67	$5.50
SCOOP	1.10	1.13	0.99
Total Company	4.30	5.58	5.69
Production taxes and other expenses ($/Boe)	$2.47	$5.54	$6.02
General and administrative expenses ($/Boe) (3)	$2.34	$2.92	$2.91
DD&A expense ($/Boe)	$21.57	$21.51	$19.47

(1) Crude oil sales volumes differ from production volumes because, at various times, we have stored crude oil in inventory due to pipeline line fill requirements, low commodity prices, or marketing disruptions or we have sold crude oil from inventory. Crude oil sales volumes were 147 MBbls more than production volumes for 2015, 408 MBbls less than production volumes for 2014, and 4 MBbls less than production volumes for 2013.

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

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(3) General and administrative expense ($/Boe) includes non-cash equity compensation expenses of $0.64 per Boe, $0.86 per Boe, and $0.80 per Boe for 2015, 2014 and 2013, respectively, and corporate relocation expenses of $0.04 per Boe for 2013.

The following table sets forth information regarding our average daily production by region for the fourth quarter of 2015:

	Fourth Quarter 2015 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	102,785	136,785	125,583
Montana Bakken	9,142	9,785	10,772
Red River units			
Cedar Hills	8,353	1,829	8,658
Other Red River units	2,560	2,619	2,996
Other	188	4,281	902
South Region:			
SCOOP	20,766	262,608	64,534
Northwest Cana/STACK	1,242	38,800	7,709
Arkoma Woodford	3	12,724	2,124
Other	537	6,729	1,658
Total	145,576	476,160	224,936

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, 2015. 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	3,700	1,196	—	—	3,700	1,196
Montana Bakken	421	272	2	1	423	273
Red River units						
Cedar Hills	137	132	—	—	137	132
Other Red River units	134	120	—	—	134	120
Other	9	4	16	4	25	8
South Region:						
SCOOP	180	123	321	97	501	220
Northwest Cana/STACK	14	10	176	57	190	67
Arkoma Woodford	1	—	383	56	384	56
Other	176	136	199	96	375	232
Total	4,772	1,993	1,097	311	5,869	2,304

Title to Properties

As is customary in the crude oil and natural gas industry, upon initiation of leasing fee mineral interests on undeveloped lands which do not have associated proved reserves, contract landmen conduct a title examination of courthouse records to determine fee mineral ownership. Such title examinations are reviewed and approved by Company landmen. Upon entering into a purchase and sale agreement for an acquisition from a third party, whether lands are producing crude oil and natural gas leases or non-producing, Company and contract landmen perform title examinations at applicable courthouses and examine the seller's internal land, legal, well, marketing and accounting records including existing title opinions. 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 commence drilling operations until we have cured material title defects as 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 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 we believe 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 crude oil production is sold to crude oil refining companies at major market centers. Other production not sold at major market centers is sold to midstream marketing companies or crude oil refining companies at the lease. We have significant production directly connected to pipeline gathering systems, with the remaining balance of our production being transported by truck or rail. Where directly marketed crude oil is transported by truck, it is delivered to a point on a connected pipeline system for delivery to a sales point “downstream” on another connecting pipeline. When crude oil is sold at the lease the sale is complete at that point.

The majority of our natural gas production is sold at our lease locations to midstream purchasers under term contracts. These contracts include multi-year term agreements 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 potential future 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 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, and on the availability of rail transportation.

For the year ended December 31, 2015, sales to Phillips 66 Company accounted for approximately 11% of our total crude oil and natural gas revenues. No other purchasers accounted for more than 10% of our total crude oil and natural gas revenues for 2015. We believe the loss of any single purchaser would 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, 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 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 and are continuously reviewed by legislators and regulators, resulting in the imposition of new or increased requirements on us and other industry participants. Applicable laws and regulations and other requirements affecting our industry often carry substantial penalties for failure to comply. These requirements may have a significant effect on the exploration, development, production and 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 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 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. Since the 1970s, the United States has 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.

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 many 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. Insofar as the interstate and intrastate transportation rates we pay are generally applicable to all comparable shippers, we believe 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. Under this standard, such pipelines must 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, access is governed by prorating provisions, which may be set forth in the pipelines' published tariffs. We believe we generally will have access to crude oil pipeline transportation services to the same extent as our similarly situated competitors.

We transport a portion of the operated crude oil production from our North region to market centers using rail transportation facilities owned and operated by third parties, with approximately 17% of such production being shipped by rail in December 2015. The U.S. Department of Transportation's ("U.S. DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") establishes safety regulations relating to crude-by-rail transportation. 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”) of the U.S. DOT, the Occupational Safety and Health Administration, as well as other federal regulatory agencies. Additionally, various state and local agencies have jurisdiction over disposal of hazardous waste and seek to 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. More recently, the FRA and PHMSA have undertaken several actions to enhance the safe transport of crude oil, including but not limited to: issuing an order requiring proper 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; moving forward with rulemaking 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. Notably, 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 issued 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 in May 2017.

We do not currently 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 are unable to estimate the potential impact on our business associated with new federal or state rail transportation regulations; however, we do not expect such regulations will affect us in a materially different way than similarly situated competitors.

At the state level, in December 2014 the North Dakota Industrial Commission ("NDIC") introduced new 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 on railcars and transported. The rules, which became effective in April 2015, 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. The regulations are designed to leave the crude oil with a vapor pressure of no more than 13.7 pounds per square inch ("psi") compared to national standards that require 14.7 psi. While the new rules could increase the cost of doing business in North Dakota, we do not expect these changes to have a material impact on us nor will they 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 that provides for national treatment of trade in natural gas; however, the U.S. DOE’s regulation of imports and exports from and to countries without such FTAs 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 that 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 that the pro-competitive regulatory approach established by the FERC will continue. However, we do not believe any action taken will affect us in a materially different way than similarly situated natural gas producers.

With regard to our physical sales of natural gas and any 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 onshore and in state waters. 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 tendency to increase our costs of getting 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 within the state on a comparable basis, we believe 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 subject to regulation under 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. All of the states in which 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, and the plugging and abandonment of wells, as well as regulations that generally limit or prohibit the venting or flaring of natural gas. The effect of these regulations is to limit the amount of crude oil and natural gas we can produce from our wells and to limit the number of wells or the locations we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production, severance or excise tax with respect to 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 in the crude oil and natural gas industry 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.

In November 2013, 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, mandatory clearing is now required for all market participants, unless an exception is available. 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 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 are in the process of adopting or implementing 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, including the restrictions on proprietary trading adopted under Section 619 of the Dodd-Frank Act, also known as the Volcker Rule, 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, new rules and regulations, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial and commercial risks related to fluctuations in commodity prices. Additional effects of the new regulations, including increased regulatory reporting and recordkeeping costs, increased regulatory capital requirements for our counterparties, and market dislocations or disruptions, among other consequences, could have an adverse effect on our ability to hedge risks associated with our business.

Additionally, the SEC had adopted rules as required under the Dodd-Frank Act requiring registrants to disclose certain payments made to the U.S. Federal government and foreign governments in connection with the commercial development of crude oil, natural gas or minerals. The disclosure requirements were challenged by certain business groups and were subsequently vacated by a Federal court in July 2013. In December 2015, the SEC issued a revised proposal for public comment. As the proposed rules are not yet final, the impact of the rules on our business is uncertain at this time.

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. Among other matters, EPAct 2005 amended the NGA to add an anti-market manipulation provision making it unlawful for any entity, including otherwise non-jurisdictional producers such as us, 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 activities of natural gas pipelines and storage companies that 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 the authority to order 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, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers, and natural gas producers, 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, and 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 that prohibit, 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 its anti-market manipulation regulations. Knowing or willful violations of the Commodity Exchange Act may also lead to a felony conviction.

Additional proposals and proceedings that may affect the crude oil and natural gas industry are pending before the U.S. Congress, the FERC and the courts. 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 by any such action in a materially different way than our similarly situated competitors.

Environmental, health and safety 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, and worker health and safety. 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, health and safety 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.

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 health, safety, and environmental (“HSE”) performance; however, at times circumstances may arise that adversely affect our compliance with applicable HSE requirements. We have established internal policies and procedures regarding HSE matters for all employees, contractors, and vendors. In connection with our HSE initiatives, we work to identify and manage our environmental and safety risks and the impact of our operations and improve our HSE efforts. We monitor our HSE performance to assess our compliance with environmental protection and safety initiatives and peer benchmarking with trade associations.

One of our HSE 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 figures. 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 that address 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. In September 2015, the NDIC extended the deadline to comply with the requirement to capture 85% of the natural gas produced from a well by one year, with a new compliance deadline of November 1, 2016.

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, 2015, we delivered approximately 87% of our operated natural gas production in North Dakota Bakken to market, flaring approximately 13% compared to 13% in 2014, 11% in 2013 and 15% in 2012. Flaring from our operated well sites in the North Dakota Bakken is less than our industry peers operating in the play. According to data published by the NDIC, our industry as a whole flared approximately 18% of produced natural gas volumes in the state during 2015. 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, Northwest Cana 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. To date, we have taken numerous actions to reduce flaring from our operated well sites. We make efforts to coordinate our well completion operations to coincide with well connections to gathering systems in order to minimize flaring, but 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 is 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.

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.

Environmental, health and safety laws, rules and regulations. Some of the existing environmental and worker health and safety laws, rules and regulations to which we are subject include, among others: (i) regulations by the Environmental Protection Agency (“EPA”) and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that may require the removal of previously disposed wastes (including wastes 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 Clean Air Act and comparable state and local requirements, which establish pollution control requirements with respect to air emissions from our operations; (v) the 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, 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 Resource Conservation and Recovery Act, which is a principal federal statute governing the treatment, storage and disposal of solid and hazardous wastes, and comparable state statutes; (viii) the Safe Drinking Water Act 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 that have the potential to significantly impact the environment; (x) the Endangered Species Act and comparable state statutes, which afford protections to certain plant and animal species; (xi) the Migratory Bird Treaty Act, which imposes certain restrictions for the protection of migratory birds; (xii) the Bald and Golden Eagle Protection Act, which imposes certain restrictions for the protection of bald and golden eagles; (xiii) the 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 naturally occurring radioactive material. Any 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 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 are being enacted to address concerns about the effects the emission of carbon dioxide and other identified "greenhouse gases" may have on the environment and climate worldwide, generally referred to as "climate change." For example, the EPA has adopted regulations under existing provisions of the federal Clean Air Act ("CAA") establishing, among other things, Prevention of Significant Deterioration ("PSD") and 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. We currently do not have any facilities that are required to adhere to the PSD or Title V permit requirements; however, attempts by the EPA to aggregate multiple oil and gas production facilities, each of which is currently and has long been regarded as an individual stationary source, for permitting purposes could result in the aggregate emissions from these independent facilities triggering Title V and/or PSD requirements. EPA rulemakings 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. In August 2015, the EPA proposed new regulations setting methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Obama Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025 even though there is consensus that oil and gas producers’ compliance with EPA's New Source Performance Standard Subpart OOOO, which was promulgated in 2012, has already achieved the methane reductions which are now being targeted by the recently proposed regulations. The proposed regulations are expected to be finalized in 2016. On January 22, 2016, the Bureau of Land Management issued a pre-publication version of a proposed venting and flaring rule, which is expected to be finalized in 2016 and, like the forthcoming EPA regulations, will address methane emissions from crude oil and natural gas sources. To the extent the new regulations 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, the impact of which, though uncertain at this time as the regulations are not yet final, is not expected to be material and will not affect us in a way that materially differs from our similarly situated competitors.

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, 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. Nonetheless, the agreement 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 adopted 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 that are 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. Although it is not possible at this time to predict how such legislation or new regulations adopted to address greenhouse gas emissions would 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. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, 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.

With respect to air quality regulation more generally, the EPA has also established air emission controls for crude oil and natural gas production and natural gas processing operations under the CAA's New Source Performance Standards and National Standards for Emission of Hazardous Air Pollutants programs. With regard to production activities, the rules require, among other things, the reduction of volatile organic compound (“VOC”) emissions from three subcategories of fractured and refractured 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 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" wells must use reduced emission completions or "green completions." The rules also established specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The rules are 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 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. 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.

Hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand 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.

Also 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. Further, in April 2015 the EPA issued proposed regulations under the Clean Water Act governing discharges to publicly owned treatment works of waste water from hydraulic fracturing and certain other natural gas operations. In 2015 the EPA completed a study of the potential impacts of hydraulic fracturing activities on water resources and published a draft assessment in June 2015 for peer review and public comment. In its assessment, the EPA indicated it did not find evidence that hydraulic fracturing mechanisms caused widespread, systemic impacts on drinking water resources in the United States. Nonetheless, the results of the study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise, and there has been recent speculation the EPA may conduct a second similar study. Finally, the U.S. Department of Interior issued final rules in March 2015 related to the regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule and a final decision remains pending.

At the state level, several states, including 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 the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. In certain areas of the United States, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards.

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 more 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 recent 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 some states, including states in which we operate, are considering additional requirements related to seismic safety. For example, the Oklahoma Corporation Commission ("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 2015, we began operation of water recycling facilities in the SCOOP area that economically reuse stimulation water for both operational efficiencies and environmental benefits.

Employees

As of December 31, 2015, we employed 1,143 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 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 historically 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 heavily influence our revenue, profitability, access to capital, capital budget and rate of growth. Crude oil and natural gas are commodities and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand, as evidenced by the significant decrease in crude oil and natural gas prices in 2014 and 2015, which has continued into 2016. Historically, the markets for crude oil and natural gas have been volatile and unpredictable. For example, the NYMEX West Texas Intermediate crude oil and Henry Hub natural gas spot prices ranged widely from approximately $35 to $61 per barrel and $1.63 to $3.32 per MMBtu, respectively, during 2015. Commodity prices are likely to remain volatile and unpredictable in 2016.

Our crude oil sales for future periods are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable. Additionally, a portion of our natural gas sales for future periods are unhedged and directly exposed to continued volatility in natural gas 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 global 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 levels of economic sanctions applied to certain producing nations;
- the level and effect of trading in commodity futures markets;
- 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 availability, proximity and capacity of transportation, processing, storage and refining facilities;
- changes in supply, demand, and refining and processing capacity for various grades of crude oil and natural gas;
- the ability of national and global refineries to accommodate domestic supplies of light sweet crude oil;
- the cost of transporting, processing, and marketing 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.

Crude oil prices remained significantly depressed in 2015 and face continued downward pressure, with crude oil prices dropping below $27 per barrel in early 2016. Natural gas prices faced similar downward pressure in 2015, dropping below

$1.70 per MMBtu in December 2015. We have established our 2016 capital program to be reflective of the current commodity price environment which will result in a reduction in our operated rig count and deferral of certain drilling projects and well completion activities in 2016. These actions could have an adverse effect on our business, financial condition, results of operations and cash flows.

In addition to reducing our revenue, cash flows and earnings, depressed prices for crude oil and natural gas may adversely affect us in a variety of ways. If commodity prices do not improve or further decrease, 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 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, as was the case in February 2016 when our corporate credit rating was downgraded by Standard & Poor's Ratings Services ("S&P") and Moody's Investor Services, Inc. ("Moody's") in response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions. These downgrades negatively impact our cost of capital, increase the borrowing costs under our revolving credit facility and $500 million term loan due in November 2018 (“three-year term loan”), and may limit our ability to access capital markets and execute aspects of our business plans. As a result, an extended continuation of the current commodity price environment, or further declines in commodity prices, will 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 geographically concentrated in the Bakken field of North Dakota and Montana, with that area comprising approximately 62% 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, 2015. Approximately 54% of our estimated proved reserves were located in the Bakken as of December 31, 2015. Additionally, in recent years we have significantly expanded our operations in Oklahoma with our discovery of the SCOOP play and our increased activity in the Northwest Cana and STACK plays. Our properties in Oklahoma comprised approximately 32% of our crude oil and natural gas production and approximately 23% of our crude oil and natural gas revenues for the year ended December 31, 2015. Approximately 42% of our estimated proved reserves were located in Oklahoma as of December 31, 2015.

Because of this concentration in limited geographic areas, the success and profitability of our operations may be disproportionately exposed to regional factors relative to our competitors that have 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, oil field 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 described above during months when drilling is possible 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, industrial accidents or labor difficulties. 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 business and financial condition.

United States and global economies may experience periods of turmoil and volatility from time to time, which may be characterized by diminished liquidity and credit availability, inability to access capital markets, high unemployment, unstable consumer confidence, and diminished consumer demand and spending. Recently, certain global economies

have experienced periods of political unrest, slowing economic growth, rising interest rates, changing economic sanctions, and currency volatility. These global macroeconomic conditions continue to put significant downward pressure on crude oil prices, and a continuation of that trend could continue or exacerbate that pressure. This negatively impacts 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 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. We have a revolving credit facility with lender commitments totaling $2.75 billion, which may be increased up to a total of $4.0 billion upon agreement with participating lenders. 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. 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 we are unable to access funding 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 financial condition, results of operations and cash flows.

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. In 2015, we invested approximately $2.56 billion in our capital program, inclusive of property acquisitions. We have budgeted $920 million for capital expenditures in 2016 (excluding acquisitions which are not budgeted) of which $784 million is allocated for exploration and development drilling. Our planned 2016 capital expenditures are substantially lower than our 2015 expenditures as a result of a planned reduction in spending prompted by significantly depressed commodity prices. We may find that additional reductions in our 2016 capital spending become necessary 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. 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 results, the availability of drilling rigs and other services and equipment, the availability of transportation 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; 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.

As a result of weakened oil and gas industry conditions from lower commodity prices, our ability to borrow may decrease and we may have limited ability to obtain the capital necessary to sustain our operations at planned levels. Our revolving credit facility has lender commitments totaling $2.75 billion, which may be increased up to a total of $4.0 billion upon agreement with participating lenders. However, we can offer no assurance that our existing or other lenders would be willing to increase their commitments under our credit facility. Such lenders could decline to do so based on our financial condition, the financial condition of our industry or the economy as a whole or other reasons beyond our control. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet capital requirements and commitments, the failure to obtain additional financing could result in a curtailment of operations relating to development of our prospects, which in turn could lead to a decline in our crude oil and natural gas reserves and could adversely affect 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. However, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional debt will require a portion of our cash flows from operations 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; and not successfully cleaning out the well bore after completion of the final fracture stimulation stage.

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;
- 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 historically 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.

Additionally, severe weather conditions and natural disasters such as flooding, 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. The consequences of such events may include the evacuation of personnel, damage to drilling rigs or pipeline and rail transportation facilities, 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 and cash flows

Reserve estimates depend on many assumptions that will 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 a continued decline in, or an extended period of historically low, 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—

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Crude Oil and Natural Gas Operations—Proved Reserves for information about our estimated crude oil and natural gas reserves, PV-10, and Standardized Measure of discounted future net cash flows as of December 31, 2015.
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 may 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 2015, 98 MMBoe of proved undeveloped reserves were removed from our year-end reserve estimates due to various factors, including removals associated with drilling locations no longer scheduled to be developed within five years from the date of initial booking. Additionally, decreases in commodity prices in 2015 shortened the economic lives of certain producing properties and caused certain exploration and development projects to become uneconomic, which resulted in downward reserve revisions totaling 251 MMBoe in 2015.
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, 2015, average prices used to calculate our estimated proved reserves were $50.28 per Bbl for crude oil and $2.58 per MMBtu for natural gas ($41.63 per Bbl for crude oil and $2.35 per Mcf for natural gas adjusted for location and quality differentials). Actual future prices may materially differ from those used in our year-end estimates.
Crude oil prices existing in February 2016 are significantly lower than the 2015 average price used to determine our year-end proved reserves. If crude oil prices do not increase significantly, our future calculations of estimated proved reserves will be based on lower prices which could result in our having to remove non-economic reserves from our proved reserves in future periods. Holding all other factors constant, if crude oil prices used in our year-end reserve estimates were decreased by $15.00 per barrel, thereby approximating the pricing environment existing in February 2016, our proved reserves at December 31, 2015 could decrease by approximately 146 MMBoe, or 12%. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve and PV-10 Sensitivities for additional proved reserve sensitivities under various 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 and, in particular, may be reduced due to the significant decline in commodity prices.
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. 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 expenses 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.

At December 31, 2015, the PV-10 value of our proved reserves totaled approximately $8.0 billion. The average prices used to estimate our proved reserves and PV-10 at December 31, 2015 were $50.28 per Bbl for crude oil and $2.58 per MMBtu for natural gas ($41.63 per Bbl for crude oil and $2.35 per Mcf for natural gas adjusted for location and quality differentials). Actual future prices may materially differ from those used in our year-end estimates.

Crude oil prices existing in February 2016 are significantly lower than the 2015 average price used to determine our year-end PV-10. Holding all other factors constant, if crude oil prices used in our year-end PV-10 estimates were decreased by $15.00 per barrel, thereby approximating the pricing environment existing in February 2016, our PV-10 at December 31, 2015 could decrease by approximately $3.4 billion, or 42%. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves—Proved Reserve and PV-10 Sensitivities for additional PV-10 sensitivities under various commodity price scenarios.

We may be required to further write down the carrying values of our crude oil and natural gas properties if commodity prices remain at their currently low levels or decline further.

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 remain at their currently low levels or decline further, 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, 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, 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. As a result of the significant decrease in commodity prices, the number of providers of the materials and services described above has decreased in the regions where we operate. As a result, the likelihood of experiencing shortages or higher costs of materials and services may be increased in connection with any period of commodity price recovery. Such shortages or high costs could delay the execution of our drilling plans or cause us to incur expenditures not provided for in our capital budget, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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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, explosions and ruptures of pipelines;
- 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 not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. 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, costs, drilling results, regulatory approvals, available transportation capacity, 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. Currently low commodity prices, reduced capital spending and numerous other factors, many of which are beyond our control, could result in our failure to establish production on undeveloped acreage, and, if we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 60% of our total net undeveloped acreage at December 31, 2015. At that date, we had leases representing 320,188 net acres expiring in 2016, 283,590 net acres expiring in 2017, and 112,478 net acres expiring in 2018. 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, 2015, approximately 57% 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, 2015 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $6.5 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 may occur in the future. A removal of such reserves could adversely affect our operations. In 2015, 98 MMBoe of proved undeveloped reserves were removed from our year-end reserve estimates due to various factors, including removals associated with drilling locations no longer scheduled to be developed within five years from the date of initial booking. Additionally, decreases in commodity prices in 2015 caused certain exploration and development projects to become uneconomic, which resulted in downward revisions of proved undeveloped reserves totaling 181 MMBoe in 2015.

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

The value we receive for our crude oil and natural gas production depends in part on the availability, proximity and capacity of 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 or the delay, or discontinuance of, development plans for properties. 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.

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 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 is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

We transport a portion of the operated crude oil production from our North region to market centers using rail transportation facilities owned and operated by third parties, with approximately 17% of such production being shipped by rail in December 2015. See Part I, Item 1. Business—Regulation of the Crude Oil and Natural Gas Industry—Regulation of sales and transportation of crude oil and natural gas liquids for a discussion of regulations impacting the transportation of crude oil by rail. Compliance with regulations, including voluntary measures adopted by the railroad industry, impacting the type, design, specifications or construction of rail cars used to transport crude oil could result in severe transportation capacity constraints during the period in which new rail cars are retrofitted or constructed to meet specifications. We do not currently own or operate rail transportation facilities or rail cars; however, compliance with 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, 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, 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. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and 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 seismic safety. 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 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 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, or the issuance of orders or judgments limiting or enjoining future operations. 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 and reduce 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") and 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. We currently do not have any facilities that are required to adhere to the PSD or Title V permit requirements; however, attempts by the EPA to aggregate multiple oil and gas production facilities, each of which is currently and has long been regarded as an individual stationary source, for permitting purposes could result in the aggregate emissions from these independent facilities triggering Title V and/or PSD requirements. EPA rulemakings 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. In August 2015, the EPA proposed new regulations setting methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Obama Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025. The proposed regulations are expected to be finalized in 2016. On January 22, 2016, the Bureau of Land Management issued a pre-publication version of a proposed venting and flaring rule, which is expected to be finalized in 2016 and, like the forthcoming EPA regulations, will address methane emissions from crude oil and natural gas sources. Recently, the EPA has increased the level of Clean Air Act enforcement activity within the upstream oil and gas sector, focusing on alleged violations related to emissions of greenhouse gases and volatile organic compounds (“VOCs”) from production facilities. To the extent the EPA experiences success in connection with enforcement efforts in a given geographical area, it may decide to extend such efforts to additional areas, including those where we have significant operations. The EPA may also choose to focus its initial efforts with respect to any new enforcement initiative on an area where we have significant operations.

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, 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. Nonetheless, the agreement 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 Congress has from time to time considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted 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 that are 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 greenhouse gases.

The adoption and implementation of 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 or install new equipment 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, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Finally, it should be noted 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 and additional operating restrictions or delays and inability 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 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 agencies are considering 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 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. Further, in April 2015 the EPA issued proposed regulations under the Clean Water Act governing discharges to publicly owned treatment works of waste water from hydraulic fracturing and certain other natural gas operations. Moreover, in 2015 the EPA completed a study of the potential impacts of hydraulic fracturing activities on water resources and published a draft assessment in June 2015 for peer review and public comment. In its assessment, the EPA indicated it did not find evidence that hydraulic fracturing mechanisms caused widespread, systemic impacts on drinking water resources in the United States. Nonetheless, the results of the study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Finally, the U.S. Department of Interior issued final rules in March 2015 related to the regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule and a final decision remains pending. As of December 31, 2015, we held approximately 181,500 net undeveloped acres on federal land, representing approximately 15% of our total net undeveloped acres.

At the state level, several states, including 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 the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. 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 legislation 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 other requirements 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, 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 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.

Future legislation may impose new taxes on crude oil or natural gas activities, including by eliminating or reducing certain federal income tax deductions currently available with respect to crude oil and natural gas exploration and development.

In recent years, legislation has been proposed to make significant changes to U.S. federal income tax laws, including the elimination or deferral of certain U.S. federal income tax deductions currently available to crude oil and natural gas exploration and production companies. Such proposed changes include, but are not limited to: (i) the repeal of the percentage depletion allowance for crude oil and natural gas properties; (ii) the elimination of current 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.

It is uncertain whether these or similar changes will be enacted or, if enacted, how soon any such changes would become effective. The passage of such legislation or any other similar change in U.S. federal income tax law could eliminate or defer certain available tax deductions within our industry, and any such changes could adversely affect our financial condition, results of operations and cash flows. Additionally, President Obama has proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an "oil fee" of $10.25 per barrel equivalent of crude oil. This fee would be collected on domestically produced and imported petroleum products. If enacted into law, the fee would be phased in over five years, beginning October 1, 2016. The adoption of this, or similar proposals, could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices companies such as ours receive for our crude oil.

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 the end user exception from any clearing requirements applicable to our swaps, the mandatory clearing requirements and revised capital requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for managing commodity price risk. Some counterparties to our derivative instruments may also need or choose to spin off some of their derivative activities to a separate entity, which may not be as credit-worthy as our current counterparty.

Further, if we do not qualify for the end user exemption, 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. 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. Additionally, if we do not qualify for the 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.

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, 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, 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.

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.

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, 2015, non-operated properties represented 20% of our estimated proved developed reserves, 9% of our estimated proved undeveloped reserves, and 13% 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, three-year term loan, 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 and three-year term loan contain restrictive covenants that limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale-leaseback transactions, and merge, consolidate or sell all or substantially all of our assets. Our revolving credit facility and three-year term loan also contain 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 (total debt 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, 2015, our consolidated net debt to total capitalization ratio, as defined, was 0.58 to 1.00. Our total debt would need to independently increase by approximately $2.6 billion, or 36%, above existing levels at December 31, 2015 (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 $1.4 billion, or 30%, below existing levels at December 31, 2015 (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 others, limit our ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, and consolidate, merge or transfer certain assets.

The covenants in our revolving credit facility, three-year term loan, 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, three-year term loan, 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, three-year term loan, 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.

Increases in interest rates could adversely affect our business.

Our business and operating results can be adversely affected by factors such as the availability, terms of and cost of capital, increases in interest rates, or a downgrade or other negative rating action with respect to our credit rating. In February 2016, our corporate credit rating was downgraded by S&P and Moody's in response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions. These downgrades will cause the interest rates on our revolving credit facility borrowings and three-year term loan to increase by 0.250% and 0.125%, respectively, and may limit our ability to pursue acquisition opportunities, reduce cash flows used for drilling and place us at a competitive disadvantage. As of February 19, 2016, outstanding variable rate borrowings under our revolving credit facility and three-year term loan totaled $1.33 billion and the impact of a 1% increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $13.3 million and an $8.2 million decrease in our annual net income. 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 ($379 million in receivables at December 31, 2015); our joint interest receivables ($232 million at December 31, 2015); and counterparty credit risk associated with our derivative instrument receivables ($108 million at December 31, 2015).

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 largest purchaser of our crude oil and natural gas during the year ended December 31, 2015 accounted for 11% 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 continuation or worsening of the depressed 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, and it is difficult to predict how long the current depressed commodity price environment will continue and the ultimate impact it will have on the parties with which we do business.

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 the prices of crude oil and natural gas, from time to time we may enter into derivative instruments for a portion of our crude oil and/or natural gas 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, 2015. 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 crude oil and natural gas 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 crude oil and natural gas reserves. We may choose not to hedge future production if the pricing environment for certain time periods is not deemed to be favorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize favorable gain positions for the purpose of funding our capital program. Our crude oil sales for future periods are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable. Additionally, a portion of our natural gas sales for future periods are unhedged and directly exposed to continued volatility in natural gas market prices, whether favorable or unfavorable.

A limited liability company for which our Chairman and Chief Executive Officer serves as sole manager 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, 2015, a limited liability company for which Harold G. Hamm, our Chairman and Chief Executive Officer, serves as sole manager 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 and the limited liability company for which he serves as sole manager 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, 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 may be subject to risks in connection with acquisitions.

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 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.

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

Our business 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 in 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 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 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 gathering, pipeline, or rail transportation systems 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.

Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2015.

Item 2. Properties

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

Item 3. Legal Proceedings

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 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 seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. On November 3, 2014, plaintiffs filed an Amended Petition that did not add any substantive claims, but sought a “hybrid class action” in which they sought certification of certain claims for injunctive relief, reserving the right to seek a further class certification on money damages in the future. Plaintiffs filed an Amended Motion for Class Certification on January 9, 2015, that modified the proposed class to royalty owners in Oklahoma production from July 1, 1993, to the present (instead of 1980 to the present) and sought certification of over 45 separate “ issues” for injunctive or declaratory relief, again, reserving the right to seek a further class certification of money damages in the future. The Company responded to the petition, its amendment, and the motions for class certification denying the allegations and raising a number of affirmative defenses and legal arguments to each of the claims and filings. Certain discovery was undertaken and the “hybrid” motion was briefed by plaintiffs and the Company. A hearing on the “hybrid” class certification was held on June 1st and 2nd, 2015. On June 11, 2015, the trial court certified a “hybrid” class as requested by plaintiffs. The Company has appealed the trial court’s class certification order, which will be reviewed de novo by the appellate court. The appeal briefing is complete and ready for determination by the court. An unsuccessful mediation was conducted on December 7, 2015. The Company is not currently able to estimate a reasonably possible loss or range of loss or what impact, if any, the action will 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 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. Although not currently at issue in the “hybrid” certification, plaintiffs have alleged underpayments in excess of $200 million that they may claim as damages, which may increase with the passage of time, a majority of which would be comprised of interest. The Company disputes plaintiffs’ claims, disputes that the case meets the requirements for a class action and is vigorously defending the case. The Company will continue to assert its defenses to the case as certified as well as any future attempt to certify a money damages class.

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.

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.

	2015				2014			
	Quarter Ended				Quarter Ended			
	March 31	June 30	September 30	December 31	March 31	June 30	September 30	December 31
High	$48.99	$53.65	$42.51	$38.16	$63.23	$79.44	$80.91	$67.25
Low	$32.51	$41.74	$22.56	$19.60	$52.00	$60.51	$65.22	$30.06
Cash Dividend	—	—	—	—	—	—	—	—

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. As of February 16, 2016, the number of record holders of our common stock was 1,157. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 53,700. On February 16, 2016, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $18.46 per share.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2015:

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 (3)
October 1, 2015 to October 31, 2015	—	—	—	—
November 1, 2015 to November 30, 2015	39,369	$34.29	—	—
December 1, 2015 to December 31, 2015	5,109	28.28	—	—
Total	44,478	$33.60	—	—

(1) In connection with restricted stock grants under the Company's 2005 Long-Term Incentive Plan ("2005 Plan") and 2013 Long-Term Incentive Plan ("2013 Plan"), we adopted a policy that enables employees to surrender shares to cover their tax liability. In May 2013, the 2013 Plan was adopted and replaced the 2005 Plan. 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 Internal Revenue Service.

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

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the vesting of restrictions on shares.

Equity Compensation Plan Information

The following table sets forth the information as of December 31, 2015 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)
	—	—	17,028,213

Equity Compensation Plans Approved by Shareholders			
Equity Compensation Plans Not Approved by Shareholders	—	—	—

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

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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 2010 through December 2015. The graph assumes the value of the investment in our common stock and in each index was $100 on December 31, 2010 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, 2011 through 2015. 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,				
	2015	2014	2013	2012	2011
Income Statement data					
In thousands, except per share data					
Crude oil and natural gas sales	$2,552,531	$4,203,022	$3,573,431	$2,349,500	$1,633,718
Gain (loss) on derivative instruments, net (1)	91,085	559,759	(191,751)	154,016	(30,049)
Total revenues	2,680,167	4,801,618	3,421,807	2,542,587	1,636,088
Income (loss) from continuing operations	(353,668)	977,341	764,219	739,385	429,072
Net income (loss)	(353,668)	977,341	764,219	739,385	429,072
Basic earnings (loss) per share:					
From continuing operations	$(0.96)	$2.65	$2.08	$2.04	$1.21
Net income (loss) per share	$(0.96)	$2.65	$2.08	$2.04	$1.21
Shares used in basic earnings (loss) per share	369,540	368,829	368,150	362,680	355,180
Diluted earnings (loss) per share:					
From continuing operations	$(0.96)	$2.64	$2.07	$2.03	$1.20
Net income (loss) per share	$(0.96)	$2.64	$2.07	$2.03	$1.20
Shares used in diluted earnings (loss) per share	369,540	370,758	369,698	363,692	356,460
Production					
Crude oil (MBbl) (2)	53,517	44,530	34,989	25,070	16,469
Natural gas (MMcf)	164,454	114,295	87,730	63,875	36,671
Crude oil equivalents (MBoe)	80,926	63,579	49,610	35,716	22,581
Average sales prices (3)					
Crude oil ($/Bbl)	$40.50	$81.26	$89.93	$84.59	$88.51
Natural gas ($/Mcf)	$2.31	$5.40	$4.87	$3.73	$4.87
Crude oil equivalents ($/Boe)	$31.48	$66.53	$72.04	$65.99	$72.45
Average costs per unit (3)					
Production expenses ($/Boe)	$4.30	$5.58	$5.69	$5.49	$6.13
Production taxes (% of oil and gas revenues)	7.8%	8.2%	8.3%	8.3%	8.0%
DD&A ($/Boe)	$21.57	$21.51	$19.47	$19.44	$17.33
General and administrative expenses ($/Boe) (4)	$2.34	$2.92	$2.91	$3.42	$3.23
Proved reserves at December 31					
Crude oil (MBbl)	700,514	866,360	737,788	561,163	326,133
Natural gas (MMcf)	3,151,786	2,908,386	2,078,020	1,341,084	1,093,832
Crude oil equivalents (MBoe)	1,225,811	1,351,091	1,084,125	784,677	508,438

Other financial data (in thousands)					
Net cash provided by operating activities	$1,857,101	$3,355,715	$2,563,295	$1,632,065	$1,067,915
Net cash used in investing activities	$(3,046,247)	$(4,587,399)	$(3,711,011)	$(3,903,370)	$(2,004,714)
Net cash provided by financing activities	$1,187,189	$1,227,715	$1,140,469	$2,253,490	$982,427
EBITDAX (5)	$1,978,896	$3,776,051	$2,839,510	$1,963,123	$1,303,959
Total capital expenditures	$2,564,301	$5,015,595	$3,841,633	$4,358,572	$2,224,096
Balance Sheet data at December 31 (in thousands)					
Total assets (6) (7)	$14,919,808	$15,076,033	$11,841,567	$9,091,918	$5,584,740
Long-term debt, including current maturities (6)	$7,117,788	$5,928,878	$4,650,889	$3,491,994	$1,236,909
Shareholders’ equity	$4,668,900	$4,967,844	$3,953,118	$3,163,699	$2,308,126

(1) 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 derivative instruments of $21.5 million, $174.4 million, ($130.2) million, $199.7 million, and $4.1 million for the years ended December 31, 2015, 2014, 2013, 2012, and 2011, 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) 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. For 2015, crude oil sales volumes were 147 MBbls more than crude oil production volumes. For 2014, crude oil sales volumes were 408 MBbls less than crude oil production volumes. For 2013, crude oil sales volumes were 4 MBbls less than crude oil production volumes. For 2012, crude oil sales volumes were 112 MBbls less than crude oil production volumes. For 2011, crude oil sales volumes were 30 MBbls less than crude oil production volumes.

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

(4) General and administrative expenses ($/Boe) include non-cash equity compensation expenses of $0.64 per Boe, $0.86 per Boe, $0.80 per Boe, $0.82 per Boe, and $0.73 per Boe for the years ended December 31, 2015, 2014, 2013, 2012, and 2011, respectively. Additionally, general and administrative expenses include corporate relocation expenses of $0.04 per Boe, $0.22 per Boe and $0.14 per Boe for the years ended December 31, 2013, 2012, and 2011. No corporate relocation expenses were incurred prior to 2011 and after 2013.

(5) We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income or operating cash flows as determined by generally accepted accounting principles. Reconciliations of net income and operating cash flows to EBITDAX are provided in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures.

(6) Balances at December 31, 2014, 2013, 2012, and 2011 have been retroactively adjusted to reflect our June 2015 adoption of Accounting Standards Update ("ASU") 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs, which resulted in the reclassification of $69.0 million, $64.9 million, $47.7 million, and $17.4 million, respectively, of unamortized debt issuance costs from "Other noncurrent assets" to a reduction of "Long-term debt, net of current portion" on the consolidated balance sheets. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies—New accounting pronouncements for further discussion.

(7) Balances at December 31, 2013, 2012, and 2011 have been retroactively adjusted to reflect our December 2015 adoption of ASU 2015-17, Balance Sheet Classification of Deferred Taxes, which resulted in the reclassification of $34.7 million, $0.4 million, and $44.0 million, respectively, of deferred income tax assets to a non-current liability classification within "Deferred income tax liabilities, net" on the consolidated balance sheets. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies—New accounting pronouncements for further discussion. No deferred income tax asset balances existed on the balance sheet at December 31, 2014 that required reclassification.

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, STACK, and Northwest Cana areas of Oklahoma.

Business Environment and Outlook

Crude oil prices remained significantly depressed in 2015 and currently face continued downward pressure due to domestic and global supply and demand factors. The downward price pressure intensified in late 2015 and early 2016, with crude oil prices dropping below $27 per barrel in February 2016, a level not seen since 2003. Natural gas prices faced similar downward pressure in 2015, dropping below $1.70 per MMBtu in December 2015.

In light of the challenges facing our industry, our primary business strategies for 2016 will include: (1) optimizing cash flows through operating efficiencies and cost reductions, (2) high-grading investments based on rates of return and opportunities to convert undeveloped acreage to acreage held by production, and (3) working to balance capital spending with cash flows to minimize new borrowings and maintain ample liquidity.

With the above strategies in mind, and given the uncertainty regarding the timing and magnitude of any price recovery, we have significantly reduced our planned non-acquisition capital spending for 2016 to $920 million, a reduction of 63% compared to $2.50 billion of non-acquisition capital spending in 2015. This non-acquisition investment level is designed to target capital expenditures and cash flows being relatively balanced for 2016 at an assumed average West Texas Intermediate benchmark crude oil price of approximately $37 per barrel for the year, with any cash flow deficiencies being funded by borrowings under our revolving credit facility. Our 2016 drilling program will focus on drilling de-risked acreage in core parts of our key operating areas that provide opportunities for converting undeveloped acreage to acreage held by production, increasing capital efficiency, reducing finding and development costs, and maximizing rates of return.

Our 2016 capital budget reflects a planned reduction in operated rig count and deferral of certain well completion activities relative to 2015, primarily in the Bakken. At December 31, 2015, we operated 23 rigs on our properties, which we subsequently reduced to 19 operated rigs in early 2016 by dropping 4 rigs in the Bakken. We expect to maintain an average of 19 operated rigs for full-year 2016 and plan to complete 71 net operated and non-operated wells in 2016, a 74% decrease compared to 271 net well completions in 2015. We plan to defer well completion activities for most of our Bakken wells in 2016, which is expected to increase our inventory of drilled but uncompleted wells during the year. As a result of these and other actions, our production is expected to decline to an average of approximately 200,000 Boe per day for 2016, a 10% decrease compared to 2015, which will likely result in lower sales volumes and revenues in 2016 compared to 2015.

2015 Results

Production

Crude oil and natural gas production totaled 80,926 MBoe (221,715 Boe per day) in 2015, an increase of 27% over 2014. Crude oil production increased 20% in 2015 and natural gas production increased 44%. Crude oil represented 66% of our 2015 production compared to 70% for 2014. SCOOP comprised 28% of our total production for 2015 compared to 20% for 2014.

Production for the fourth quarter of 2015 totaled 20,694 MBoe (224,936 Boe per day), a 1% decrease compared to the third quarter of 2015 and 16% higher than the fourth quarter of 2014. Crude oil represented 65% of our production for the 2015 fourth quarter compared to 71% for the 2014 fourth quarter.

Our total Bakken production was 50,049 MBoe (137,120 Boe per day) for 2015, a 20% increase over 2014. Fourth quarter 2015 production in the Bakken totaled 12,545 MBoe (136,355 Boe per day), a 1% increase over the third quarter of 2015 and 4% higher than the fourth quarter of 2014.

Production in SCOOP totaled 22,479 MBoe (61,586 Boe per day) for 2015, a 75% increase over 2014. SCOOP production for the 2015 fourth quarter totaled 5,937 MBoe (64,534 Boe per day), a 7% decrease compared to the third quarter of 2015 and 60% higher than the fourth quarter of 2014.

Revenues

Crude oil and natural gas revenues for 2015 decreased 39% compared to 2014 driven by a 50% decrease in realized crude oil prices and a 57% decrease in realized natural gas prices, the effect of which was partially offset by a 22% increase in crude oil sales volumes and a 44% increase in natural gas sales volumes.

Crude oil and natural gas revenues totaled $551.4 million for the 2015 fourth quarter, a 12% decrease from the 2015 third quarter and 39% lower than the 2014 fourth quarter. Crude oil sales prices for the 2015 fourth quarter averaged $34.23 per barrel, a 12% decrease from the 2015 third quarter and 44% lower than the 2014 fourth quarter. Crude oil sales volumes for the 2015 fourth quarter totaled 13,453 MBbls, a 1% decrease from the 2015 third quarter and 8% higher than the 2014 fourth quarter. Natural gas sales prices for the 2015 fourth quarter averaged $2.07 per Mcf, a 7% decrease from the 2015 third quarter and 52% lower than the 2014 fourth quarter. Natural gas sales volumes for the 2015 fourth quarter totaled 43,807 MMcf, a 2% decrease from the 2015 third quarter and 41% higher than the 2014 fourth quarter.

Proved reserves

At December 31, 2015, our proved reserves totaled 1,226 MMBoe, a decrease of 9% from proved reserves of 1,351 MMBoe at December 31, 2014. Extensions and discoveries from our drilling activities added 253 MMBoe of proved reserves in 2015, which was more than offset by downward reserve revisions totaling 297 MMBoe prompted by lower commodity prices and changes in drilling plans and 81 MMBoe of production during the year. The 12-month average price used to determine year-end proved reserves for crude oil decreased 47% from $94.99 per Bbl for 2014 to $50.28 per Bbl for 2015, while the 12-month average price for natural gas decreased 41% from $4.35 per MMBtu for 2014 to $2.58 per MMBtu for 2015.

Bakken proved reserves totaled 663 MMBoe at year-end 2015, a decrease of 23% from 866 MMBoe at year-end 2014.

SCOOP proved reserves increased 12% from 370 MMBoe at year-end 2014 to 413 MMBoe at year-end 2015.

SCOOP represented 34% of our total proved reserves at December 31, 2015 compared to 27% at year-end 2014.

Crude oil comprised 57%, or 701 MMBoe, of our proved reserves at December 31, 2015 compared to 64% at year-end 2014. The decreased percentage of crude oil reserves resulted primarily from the increase in SCOOP reserves as a percentage of our total reserves during the year, which have a higher concentration of liquids-rich natural gas compared to other operating areas such as the Bakken.

Proved property impairments

Decreases in commodity prices in 2015 adversely impacted the recoverability of capitalized costs in certain operating areas and contributed to the recognition of non-cash impairment charges for proved properties totaling $139 million for the year, of which $28 million was recognized in the fourth quarter due to continued commodity price declines. The 2015 impairments were concentrated in non-core areas of our North and South regions.

Capital expenditures and drilling activity

Non-acquisition capital expenditures totaled $394.0 million for the fourth quarter of 2015 compared to $540.0 million for the third quarter, $585.5 million for the second quarter, and $983.8 million for the first quarter. Full year 2015 non-acquisition capital expenditures totaled approximately $2.50 billion, or approximately $200 million below our 2015 capital budget.

For the quarter and year to date periods of 2015 we participated in the drilling and completion of the following number of wells by area:

	1Q 2015		2Q 2015		3Q 2015		4Q 2015		YTD 2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
North Dakota Bakken	210	62	160	56	168	35	103	22	641	175
Montana Bakken	8	6	1	—	—	—	—	—	9	6
SCOOP	74	37	55	18	37	11	38	8	204	74
Northwest Cana	—	—	5	2	5	2	4	2	14	6
STACK	—	—	1	—	5	1	6	3	12	4
Other	12	6	4	—	1	—	—	—	17	6
Total wells	304	111	226	76	216	49	151	35	897	271

As of December 31, 2015 we had approximately 170 gross (131 net) operated wells that are drilled but not yet completed. Due to current market conditions we have chosen to defer completions on certain wells until commodity prices improve.

Credit facility and liquidity

In February 2015, aggregate lender commitments on our revolving credit facility were increased from $1.75 billion to $2.5 billion and were increased again in November 2015 to $2.75 billion to provide additional liquidity. Further, in November 2015 we entered into a $500 million unsecured term loan maturing in November 2018 and used the proceeds therefrom to repay a portion of our outstanding credit facility borrowings to further enhance our liquidity. At December 31, 2015, we had $11.5 million of cash and cash equivalents and $1.9 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $853 million of outstanding borrowings on our credit facility at December 31, 2015.

Credit facility borrowings, net of repayments and exclusive of the use of term loan proceeds, totaled $8 million for the 2015 fourth quarter compared to $120 million for the third quarter, $270 million for the second quarter, and $790 million for the first quarter. This decreasing trend resulted from a reduction in capital expenditures due to our efforts to align spending with cash flows in response to decreased commodity prices. Our total debt was nearly flat at December 31, 2015 compared to September 30, 2015.

Financial and operating highlights

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

- Volumes of crude oil and natural gas produced;
- Crude oil and natural gas prices realized;
- Per unit operating and administrative costs; and
- EBITDAX (a non-GAAP financial measure).

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,		
	2015	2014	2013
Average daily production:			
Crude oil (Bbl per day)	146,622	121,999	95,859
Natural gas (Mcf per day)	450,558	313,137	240,355
Crude oil equivalents (Boe per day)	221,715	174,189	135,919
Average sales prices:			
Crude oil ($/Bbl)	$40.50	$81.26	$89.93
Natural gas ($/Mcf)	$2.31	$5.40	$4.87
Crude oil equivalents ($/Boe)	$31.48	$66.53	$72.04
Crude oil sales price differential to NYMEX ($/Bbl)	$(8.33)	$(10.81)	$(8.23)
Natural gas sales price premium (discount) to NYMEX ($/Mcf)	$(0.34)	$1.02	$1.21
Production expenses ($/Boe)	$4.30	$5.58	$5.69
Production taxes (% of oil and gas revenues)	7.8%	8.2%	8.3%
DD&A ($/Boe)	$21.57	$21.51	$19.47
General and administrative expenses ($/Boe) (1)	$1.70	$2.06	$2.11
Non-cash equity compensation ($/Boe)	$0.64	$0.86	$0.80
Net income (loss) (in thousands)	$(353,668)	$977,341	$764,219
Diluted net income (loss) per share	$(0.96)	$2.64	$2.07
EBITDAX (in thousands) (2)	$1,978,896	$3,776,051	$2,839,510

(1) Excludes non-cash equity compensation expense.

(2) We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided subsequently under the heading Non-GAAP Financial Measures.

Results of Operations

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

	Year Ended December 31,		
In thousands, except sales price data	2015	2014	2013
Crude oil and natural gas sales	$2,552,531	$4,203,022	$3,573,431
Gain (loss) on derivative instruments, net (1)	91,085	559,759	(191,751)
Crude oil and natural gas service operations	36,551	38,837	40,127
Total revenues	2,680,167	4,801,618	3,421,807
Operating costs and expenses	(2,904,168)	(2,933,782)	(1,976,040)
Other expenses, net (2)	(311,084)	(305,798)	(232,718)
Income (loss) before income taxes	(535,085)	1,562,038	1,213,049
(Provision) benefit for income taxes	181,417	(584,697)	(448,830)
Net income (loss)	$(353,668)	$977,341	$764,219
Production volumes:			
Crude oil (MBbl)	53,517	44,530	34,989
Natural gas (MMcf)	164,454	114,295	87,730
Crude oil equivalents (MBoe)	80,926	63,579	49,610
Sales volumes:			
Crude oil (MBbl)	53,664	44,122	34,985
Natural gas (MMcf)	164,454	114,295	87,730
Crude oil equivalents (MBoe)	81,073	63,172	49,607
Average sales prices:			
Crude oil ($/Bbl)	$40.50	$81.26	$89.93
Natural gas ($/Mcf)	$2.31	$5.40	$4.87
Crude oil equivalents ($/Boe)	$31.48	$66.53	$72.04

(1) The year 2014 includes $433 million of pre-tax gains recognized from crude oil derivative contracts that were settled in the fourth quarter of that year prior to their contractual maturities.

(2) The year 2014 includes a loss on extinguishment of debt of $24.5 million related to the July 2014 redemption of our 8.25% Senior Notes due 2019.

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

Production

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

	Year Ended December 31,				Volume increase	Volume percent increase
	2015		2014			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	53,517	66 %	44,530	70 %	8,987	20 %
Natural Gas (MMcf)	164,454	34 %	114,295	30 %	50,159	44 %
Total (MBoe)	80,926	100 %	63,579	100 %	17,347	27 %

	Year Ended December 31,				Volume increase	Percent increase
	2015		2014			
	MBoe	Percent	MBoe	Percent		
North Region	54,956	68 %	47,206	74 %	7,750	16 %
South Region	25,970	32 %	16,373	26 %	9,597	59 %
Total	80,926	100 %	63,579	100 %	17,347	27 %

The 20% increase in crude oil production in 2015 compared to 2014 was driven by increased production from our properties in North Dakota Bakken and SCOOP. Production in North Dakota Bakken increased 6,623 MBbls, or 21%, over the prior year, while SCOOP production increased 3,545 MBbls, or 97%. Production growth in these areas was primarily due to additional drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease in production from our properties in Montana Bakken and the Red River units totaling 1,280 MBbls, or 14%, compared to the prior year due to a combination of natural declines in production and reduced drilling activity.

The 44% increase in natural gas production in 2015 compared to 2014 was driven by increased production from our properties in the SCOOP, Bakken, and Northwest Cana/STACK areas due to additional wells being completed and producing subsequent to December 31, 2014. Natural gas production in SCOOP increased 36,670 MMcf, or 67% over the prior year, while Bakken production increased 13,842 MMcf, or 37%, and Northwest Cana/STACK production increased 836 MMcf, or 8%. 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 30% in 2014 to 34% in 2015 primarily resulted from the significant increase in SCOOP production over the past year due in part to a shift in our well completion activities away from the Bakken to higher rate-of-return areas in Oklahoma. Our properties in SCOOP, as well as those in STACK and Northwest Cana, typically produce a higher concentration of liquids-rich natural gas compared to oil-weighted properties in the Bakken. For 2016, we expect to continue shifting our well completion activities to Oklahoma and plan to allocate an increased proportion of our capital spending to the SCOOP, STACK, and Northwest Cana areas. Accordingly, we expect our natural gas production may increase to approximately 40% of our total production for 2016. As crude oil prices recover, we expect to increase our completion activities in the Bakken and shift our production back to a higher proportion of crude oil.

Our reduction in capital spending and deferral of well completion activities in 2015, which is expected to intensify in 2016, has adversely impacted our production growth and our 27% year-over-year growth in production realized in 2015 will not be sustained in 2016. We expect our production will average approximately 200,000 Boe per day for the full year of 2016, a 10% decrease from average daily production of 221,715 Boe per day for 2015.

Revenues

Our revenues primarily consist of sales of crude oil and natural gas and gains and losses resulting from changes in the fair value of our derivative instruments.

Crude oil and natural gas sales. Crude oil and natural gas sales for 2015 were $2.55 billion, a 39% decrease from sales of $4.20 billion for 2014 primarily due to a significant decrease in commodity prices, partially offset by an increase in sales volumes.

Our crude oil sales prices averaged $40.50 per barrel for 2015, a decrease of 50% compared to $81.26 for 2014. Market prices for crude oil remained depressed throughout 2015, resulting in significantly lower realized sales prices compared to the prior year. The differential between NYMEX West Texas Intermediate ("WTI") calendar month crude oil prices and our realized crude oil prices averaged $8.33 per barrel for 2015 compared to $10.81 for 2014. The improved differential was due in part to increased availability and use of pipeline transportation in the current year to move our crude oil to market with less dependence on more costly rail transportation.

Our realized natural gas sales prices averaged $2.31 per Mcf for 2015, a decrease of 57% compared to $5.40 per Mcf for 2014 due to lower market prices for natural gas and natural gas liquids ("NGLs"). 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 the purchasers extract from our sales stream. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a discount of $0.34 per Mcf for 2015 compared to a premium of $1.02 for 2014. NGL prices in 2015 remained depressed in conjunction with low crude oil prices, which reduced the value of our natural gas sales stream and unfavorably impacted the difference between our realized prices and Henry Hub benchmark pricing. If NGL prices do not recover from current levels, the prices we receive for the sale of our natural gas stream in 2016 may continue to be lower than Henry Hub benchmark prices.

Our sales volumes for 2015 increased 17,901 MBoe, or 28%, over 2014 primarily due to an increase in producing wells resulting from the success of our drilling programs in North Dakota Bakken and SCOOP. 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 produced and sold crude oil volumes. New third party pipeline systems becoming available during 2015 provided for improved transportation of our crude oil to market, which resulted in the sale of

crude oil previously stored in inventory and caused crude oil sales volumes to be higher than crude oil production by 147 MBbls for the year.
For the 2015 fourth quarter, crude oil and natural gas revenues totaled $551.4 million, representing a 12% decrease from 2015 third quarter revenues of $628.5 million and a 39% decrease from 2014 fourth quarter revenues of $902.3 million. Revenues for the 2015 fourth quarter were adversely impacted by a decrease in crude oil and natural gas prices late in the year. Our crude oil sales prices averaged $34.23 per barrel in the 2015 fourth quarter compared to $38.95 for the 2015 third quarter and $61.53 for the 2014 fourth quarter. Our natural gas sales prices averaged $2.07 per Mcf in the 2015 fourth quarter compared to $2.23 for the 2015 third quarter and $4.36 for the 2014 fourth quarter. The decrease in crude oil prices in late 2015 continued into early 2016. As a result, we expect our realized crude oil sales prices for the 2016 first quarter will be lower than those realized in the 2015 fourth quarter. Crude oil, natural gas and NGL prices have experienced significant volatility in recent months and we are unable to predict the impact future price changes may have on our full year 2016 revenues and differentials.
Crude oil represented 85% of our total crude oil and natural gas revenues for both 2015 and 2014. As previously mentioned, for 2016 we expect to allocate an increased proportion of our capital spending to our SCOOP, STACK, and Northwest Cana properties which typically contain higher concentrations of liquids-rich natural gas compared to our properties in the Bakken. Accordingly, unless crude oil prices recover significantly, we expect crude oil to comprise a smaller percentage of our 2016 revenues compared to 2015, the extent of which is uncertain due to the unpredictable nature of commodity prices.
Derivatives. Changes in natural gas prices during 2015 had a favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $91.1 million for the year. Our revenues may continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in commodity prices.
The following table presents cash settlements on matured or liquidated derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented.

	Year ended December 31,	
In thousands	2015	2014
Cash received (paid) on derivatives:		
Crude oil derivatives (1)	$—	$396,901
Natural gas derivatives	69,553	(11,551)
Cash received on derivatives, net	69,553	385,350
Non-cash gain on derivatives:		
Crude oil derivatives	4,715	89,894
Natural gas derivatives	16,817	84,515
Non-cash gain on derivatives, net	21,532	174,409
Gain on derivative instruments, net	$91,085	$559,759

(1) Net cash receipts for crude oil derivatives in 2014 include $433 million of proceeds received from crude oil derivative contracts that were settled in the fourth quarter of 2014 prior to their contractual maturities.

Operating Costs and Expenses

Production expenses. Production expenses decreased 1% to $348.9 million in 2015 from $352.5 million in 2014. Production expenses on a per-Boe basis decreased to $4.30 for 2015 compared to $5.58 for 2014. These decreases primarily resulted from curtailed spending and reduced service costs being realized in response to depressed commodity prices, increased availability and use of water gathering and recycling facilities in 2015, and a higher portion of our production coming from natural gas wells in the SCOOP area which typically have lower operating costs compared to the Bakken.
Production taxes and other expenses. Production taxes and other expenses decreased $149.2 million, or 43%, to $200.6 million in 2015 compared to $349.8 million in 2014 primarily due to lower crude oil and natural gas revenues resulting from the significant decrease in commodity prices over the prior year. 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 were 7.8% for 2015 compared to 8.2% for 2014, the decrease of which resulted from significant growth over

the past year in our SCOOP operations and resulting increase in revenues coming from Oklahoma, which has lower production tax rates compared to the Bakken. We expect this downward trend in our average production tax rate to continue in 2016 as our operations in Oklahoma continue to grow in significance and given the passing of a new law in North Dakota in 2015 that decreased the combined production tax rate in that state from 11.5% to 10.0% of crude oil revenues effective January 1, 2016.

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	2015	2014
Geological and geophysical costs	$11,032	$26,388
Exploratory dry hole costs	8,381	23,679
Exploration expenses	$19,413	$50,067

The decrease in geological and geophysical expenses in 2015 was due to changes in the timing and amount of costs incurred by the Company and recouped from joint interest owners between periods.

Dry hole costs incurred in 2015 primarily reflect costs associated with an unsuccessful well in an exploratory prospect in our North region.

Depreciation, depletion, amortization and accretion (“DD&A”). Total DD&A increased $390.4 million, or 29%, in 2015 compared to 2014 primarily due to a 28% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Year ended December 31,	
$/Boe	2015	2014
Crude oil and natural gas properties	$21.18	$21.13
Other equipment	0.33	0.32
Asset retirement obligation accretion	0.06	0.06
Depreciation, depletion, amortization and accretion	$21.57	$21.51

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 would increase. Downward revisions of proved reserves in 2015 prompted by depressed commodity prices contributed to a slight increase in our DD&A rate for crude oil and natural gas properties this year. If commodity prices remain at current levels for an extended period or decline further, additional downward revisions of proved reserves may occur in the future, which may be significant and would result in an increase in our DD&A rate. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.

Property impairments. Total property impairments decreased $214.8 million, or 35%, to $402.1 million for 2015 compared to $616.9 million for 2014.

Impairments of proved properties decreased $185.4 million, or 57%, in 2015 to $138.9 million, of which $27.5 million was recognized in the fourth quarter. The decrease resulted from differences in the severity of commodity price declines and resulting impact on fair value assessments between periods. The sharp pronounced decrease in forward commodity prices in late 2014 triggered significant impairments of previously unimpaired proved properties, with subsequent commodity price changes and impairments in 2015 being less severe.

The 2015 proved property impairments reflect fair value adjustments primarily concentrated in an emerging area with minimal production and costly reserve additions ($42.5 million), the Medicine Pole Hills units ($32.5 million, including $9.6 million in the fourth quarter), the Buffalo Red River units ($26.3 million), non-Bakken areas of North Dakota and Montana ($8.2 million), Wyoming properties ($17.9 million, all in the fourth quarter), and various legacy areas in the South region ($11.4 million).

Estimated reserves are a key component in assessing proved properties for impairment. If commodity prices remain at current levels for an extended period or decline further, downward revisions of reserves may be significant in the future and could result in additional impairments of proved properties in 2016. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on future impairments, if any.

Impairments of non-producing properties decreased $29.3 million, or 10%, in 2015 to $263.3 million, of which $53.5 million was recognized in the fourth quarter. The decrease was due to a lower balance of unamortized leasehold costs in the current year 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. In 2014, the amortization of undeveloped leasehold costs for an exploratory prospect in Texas was accelerated in response to unsuccessful results and decreased crude oil prices, which resulted in the recognition of $92.4 million of non-producing leasehold impairment charges for the prospect in 2014, with no leasehold impairments of a similar magnitude in 2015. This decrease was partially offset by higher rates of amortization being applied in 2015 to undeveloped leasehold costs across various prospects resulting from a reduction in planned drilling activities prompted by the continued decrease in commodity prices in 2015. Our rates of amortization may increase in future periods if commodity prices remain at current levels or decline further and additional changes are made to drilling plans.

General and administrative expenses. Total general and administrative ("G&A") expenses increased $5.1 million, or 3%, to $189.8 million in 2015 from $184.7 million in 2014. G&A expenses include non-cash charges for equity compensation of $51.8 million and $54.4 million for 2015 and 2014, respectively.

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

	Year ended December 31,	
$/Boe	2015	2014
General and administrative expenses	$1.70	$2.06
Non-cash equity compensation	0.64	0.86
Total general and administrative expenses	$2.34	$2.92

The decrease in G&A expenses on a per-Boe basis in 2015 was driven by a 28% increase in sales volumes from new well completions with no comparable increase in G&A expenses. Per-Boe G&A expenses may continue to trend downward in 2016 as a result of our ongoing efforts to reduce spending in response to depressed commodity prices. The decrease in non-cash equity compensation expense on a per-Boe basis was 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 2015, coupled with the increase in sales volumes from new well completions with no comparable increase in equity compensation expense.

Interest expense. Interest expense increased $29.2 million, or 10%, to $313.1 million in 2015 from $283.9 million in 2014 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for 2015 was $6.9 billion with a weighted average interest rate of 4.4% compared to averages of $5.6 billion and 4.9% for 2014. The increase in outstanding debt resulted from borrowings incurred subsequent to December 31, 2014 to fund our 2015 capital program.

Income Taxes. We recorded an income tax benefit for the year ended December 31, 2015 of $181.4 million compared to income tax expense of $584.7 million for 2014, resulting in effective tax rates of approximately 34% and 37%, respectively, after taking into account permanent taxable differences and valuation allowances. For 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. Our 2015 effective tax rate was impacted by a $13.5 million valuation allowance recognized against deferred tax assets associated with operating loss carryforwards generated by our Canadian subsidiary during the year for which we do not believe we will realize a benefit.

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

Production

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

	Year Ended December 31,						Volume increase	Volume percent increase	
	2014			2013					
	Volume	Percent		Volume	Percent				
Crude oil (MBbl)	44,530	70	%	34,989	71	%	9,541	27	%
Natural Gas (MMcf)	114,295	30	%	87,730	29	%	26,565	30	%
Total (MBoe)	63,579	100	%	49,610	100	%	13,969	28	%

	Year Ended December 31, 2014 MBoe	Percent	2013 MBoe	Percent	Volume increase	Percent increase
North Region	47,206	74 %	38,023	77 %	9,183	24 %
South Region	16,373	26 %	11,587	23 %	4,786	41 %
Total	63,579	100 %	49,610	100 %	13,969	28 %

Crude oil production increased 9,541 MBbls, or 27%, in 2014 compared to 2013. Production in the Bakken field increased 8,371 MBbls, or 31%, over the prior year, while SCOOP production increased 1,648 MBbls, or 82%. Production growth in these areas was primarily due to increased drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease of 132 MBbls associated with non-strategic properties in Colorado and Wyoming that were sold in March 2014. Additionally, production from our properties in the Red River units decreased 336 MBbls, or 7%, over the prior year due to a combination of natural declines in production and reduced drilling activity.

Natural gas production increased 26,565 MMcf, or 30%, in 2014 compared to 2013. Production in the Bakken field increased 7,728 MMcf, or 26%, in 2014 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in the play. Natural gas production in SCOOP increased 25,579 MMcf, or 87%, due to additional wells being completed and producing in 2014 compared to 2013. These increases were partially offset by decreases in production from various areas in our North and South regions, primarily in Arkoma Woodford and Northwest Cana, due to natural declines in production.

Revenues

Crude oil and natural gas sales. Crude oil and natural gas sales for 2014 were $4.20 billion, an 18% increase from sales of $3.57 billion for 2013. Our sales volumes increased 13,565 MBoe, or 27%, over 2013 primarily due to the success of our drilling programs in the Bakken and SCOOP plays. Realized commodity prices decreased 8% in 2014 resulting from the significant decrease in crude oil prices in the 2014 fourth quarter along with a widening of sales price differentials.

Crude oil represented 85% of our total 2014 crude oil and natural gas revenues compared to 88% for 2013. The decreased percentage of crude oil revenues resulted from a significant increase in SCOOP revenues as a percentage of our total revenues in 2014. Our properties in SCOOP produce a higher concentration of liquids-rich natural gas compared to certain other operating areas such as the Bakken.

An increase in crude oil line fill requirements associated with new pipelines put into service during 2014 along with initial tank fill at new storage facilities contributed to an increase in crude oil stored in inventory in 2014. This caused crude oil sales volumes to be lower than crude oil production by 408 MBbls for 2014, with 143 MBbls of the difference occurring during the fourth quarter.

Crude oil and natural gas revenues totaled $902.3 million for the fourth quarter of 2014, representing a 22% decrease from 2014 third quarter revenues of $1.16 billion and nearly flat compared to 2013 fourth quarter revenues of $903.2 million. Revenues for the 2014 fourth quarter were adversely impacted by increased crude oil inventory levels and decreased crude oil prices. Our crude oil sales prices averaged $61.53 per barrel in the 2014 fourth quarter compared to $85.49 for the 2014 third quarter and $84.47 for the 2013 fourth quarter.

The differential between NYMEX West Texas Intermediate ("WTI") calendar month crude oil prices and our realized crude oil prices averaged $10.81 per barrel for 2014 compared to $8.23 for 2013. Our crude oil price differential to WTI averaged $11.35 per barrel in the 2014 fourth quarter compared to $11.77 for the 2014 third quarter and $13.05 for the 2013 fourth quarter.

Our realized natural gas sales prices averaged $5.40 per Mcf for 2014, an increase of 11% over $4.87 per Mcf for 2013. This increase primarily reflected improved prices realized in connection with higher market prices for natural gas during 2014. Our average natural gas sales price for the 2014 fourth quarter decreased to $4.36 per Mcf compared to $5.10 for the 2014 third quarter and $5.11 for the 2013 fourth quarter. This decrease was driven by lower sales prices for natural gas liquids in late 2014, which reduced the total value of our natural gas sales stream. NGL prices decreased significantly in late 2014 in conjunction with the decrease in crude oil prices.

The premium of our realized natural gas sales prices over NYMEX Henry Hub calendar month natural gas prices averaged $1.02 per Mcf for 2014 compared to $1.21 per Mcf for 2013. The smaller premium in 2014 was partly driven by the aforementioned decrease in NGL market prices in late 2014, which unfavorably impacted the premium of our realized prices over Henry Hub benchmark pricing. Because of significantly lower NGL prices in late 2014, our natural gas sales price premium decreased to $0.35 per Mcf for the 2014 fourth quarter compared to $1.04 for the 2014 third quarter and $1.51 for the 2013 fourth quarter.

Derivatives. Changes in commodity prices during 2014 had an overall favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $560 million for 2014, including $433 million of gains recognized on crude oil derivative liquidations in the 2014 fourth quarter.

The following table presents cash settlements on matured or liquidated derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented.

	Year ended December 31,	
In thousands	2014	2013
Cash received (paid) on derivatives:		
Crude oil derivatives (1)	$396,901	$(71,156)
Natural gas derivatives	(11,551)	9,601
Cash received (paid) on derivatives, net	385,350	(61,555)
Non-cash gain (loss) on derivatives:		
Crude oil derivatives	89,894	(126,167)
Natural gas derivatives	84,515	(4,029)
Non-cash gain (loss) on derivatives, net	174,409	(130,196)
Gain (loss) on derivative instruments, net	$559,759	$(191,751)

(1) Net cash receipts for crude oil derivatives in 2014 include $433 million of proceeds received from crude oil derivative contracts that were settled in the fourth quarter of 2014 prior to their contractual maturities.

Operating Costs and Expenses

Production expenses. Production expenses increased 25% to $352.5 million in 2014 from $282.2 million in 2013. This increase was primarily the result of an increase in the number of producing wells and resulting 28% increase in production volumes. Production expense per Boe decreased to $5.58 for 2014 compared to $5.69 for 2013.

Production taxes and other expenses. Production taxes and other expenses increased $51.0 million, or 17%, to $349.8 million in 2014 compared to $298.8 million in 2013 primarily as a result of higher crude oil and natural gas revenues driven by increased sales volumes. Production taxes as a percentage of crude oil and natural gas revenues were 8.2% for 2014 compared to 8.3% for 2013.

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

	Year ended December 31,	
In thousands	2014	2013
Geological and geophysical costs	$26,388	$25,597
Exploratory dry hole costs	23,679	9,350
Exploration expenses	$50,067	$34,947

Dry hole costs increased $14.3 million resulting from an increase in the scope of our exploratory drilling program in 2014 and primarily reflect costs associated with exploratory wells targeting non-Bakken formations in North Dakota and Montana and non-core areas in Oklahoma, Texas and Wyoming.

Depreciation, depletion, amortization and accretion. Total DD&A increased $393.0 million, or 41%, in 2014 compared to 2013 primarily due to a 27% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Year ended December 31,	
$/Boe	2014	2013
Crude oil and natural gas properties	$21.13	$19.17
Other equipment	0.32	0.24
Asset retirement obligation accretion	0.06	0.06
Depreciation, depletion, amortization and accretion	$21.51	$19.47

The increase in DD&A per Boe in 2014 resulted from an increased use of enhanced completion methods that increased completed well costs. Additionally, certain exploratory wells, primarily in non-core areas, resulted in more expensive reserve additions. These factors contributed to an increase in DD&A on a per-Boe basis in 2014 compared to 2013.

Property impairments. Total property impairments increased $396.4 million, or 180%, to $616.9 million for 2014 compared to $220.5 million for 2013 due primarily to write-downs resulting from the significant decrease in crude oil prices in the 2014 fourth quarter which adversely impacted the recoverability of capitalized costs in certain operating areas.

Impairment provisions for proved properties increased $272.5 million, or 526%, in 2014 to $324.3 million, of which $255.0 million was recognized in the fourth quarter. The 2014 impairments were primarily concentrated in the Buffalo Red River units ($96.9 million), the Medicine Pole Hills units ($75.9 million), various non-core areas in our South region ($39.7 million), non-Bakken areas of North Dakota and Montana ($18.4 million), and certain emerging areas with limited production history and costly reserve additions ($75.2 million). Impairments for 2014 also include an $18.2 million lower of cost or market adjustment for crude oil inventories.

Impairments of non-producing properties increased $123.9 million, or 73%, in 2014 to $292.6 million, of which $138.8 million was recognized in the fourth quarter. The increase was due to higher rates of amortization being applied to undeveloped leasehold costs resulting from changes in management's estimates of undeveloped properties not expected to be developed before lease expiration, particularly in the fourth quarter in response to the significant decrease in crude oil prices which altered our drilling plans. Undeveloped leasehold costs for a prospect in Texas in the early stages of exploration and development were written down in 2014 due to changes in drilling plans in response to unsuccessful results and lower crude oil prices, which resulted in the recognition of $92.4 million of non-producing leasehold impairment charges for the prospect, of which $84.6 million was recognized in the fourth quarter.

General and administrative expenses. G&A expenses increased $40.3 million, or 28%, to $184.7 million in 2014 from $144.4 million in 2013. G&A expenses include non-cash charges for equity compensation of $54.4 million and $39.9 million for 2014 and 2013, respectively. The increase in equity compensation resulted from a higher value of restricted stock grants being made in 2014 due to employee growth, which resulted in increased expense recognition compared to the prior year.

G&A expenses other than equity compensation increased $25.8 million, or 25%, in 2014 compared to 2013. The increase was primarily due to an increase in personnel costs and office-related expenses associated with our employee growth. In 2014, our Company grew from having 929 total employees in December 2013 to 1,188 total employees in December 2014, a 28% increase.

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

	Year ended December 31,	
$/Boe	2014	2013
General and administrative expenses	$2.06	$2.07
Non-cash equity compensation	0.86	0.80
Corporate relocation expenses	—	0.04
Total general and administrative expenses	$2.92	$2.91

Interest expense. Interest expense increased $48.6 million, or 21%, to $283.9 million in 2014 from $235.3 million in 2013 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the year ended December 31, 2014 was $5.6 billion with a weighted average interest rate of 4.9% compared to averages of $4.3 billion and 5.2% for 2013. The increase in outstanding debt resulted from higher borrowings being incurred to fund our increased capital budget.

Income Taxes. We recorded income tax expense of $584.7 million for 2014 compared to $448.8 million for 2013. We provided for income taxes at a combined federal and state tax rate of approximately 37% for both 2014 and 2013 after taking into account permanent taxable differences.

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 and equity securities. At December 31, 2015, we had $11.5 million of cash and cash equivalents and approximately $1.9 billion of borrowing availability on our revolving credit facility after considering outstanding borrowings and letters of credit. We are focused on balancing our 2016 capital spending with cash flows in order to

minimize new borrowings and maintain ample liquidity. At February 19, 2016, outstanding borrowings totaled $830 million with approximately $1.9 billion of borrowing availability on our credit facility.
Based on our 2016 capital expenditure budget, our forecasted cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our credit facility, three-year term loan, 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.
Cash Flows
Cash flows from operating activities
Our net cash provided by operating activities was $1.86 billion and $3.36 billion for the years ended December 31, 2015 and 2014, respectively. The decrease in operating cash flows was primarily due to lower crude oil and natural gas revenues driven by lower realized commodity prices, a decrease in cash gains on derivative settlements, and an increase in interest expense over the past year, all partially offset by lower production taxes.
If the depressed commodity price environment existing in February 2016 persists or worsens, we expect our 2016 operating cash flows will be lower than 2015 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, 2015 and 2014, we had cash flows used in investing activities (excluding proceeds from asset sales and other) of $3.08 billion and $4.72 billion, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $61.0 million and $203.9 million for the years ended December 31, 2015 and 2014, respectively. Cash capital expenditures excluding acquisitions totaled $3.02 billion and $4.51 billion for the years ended December 31, 2015 and 2014, respectively, the decrease of which was driven by a decrease in our capital budget and related drilling activity for 2015. Our cash capital expenditures for 2015 include the payment of amounts owed at December 31, 2014 in connection with our 2014 drilling program and associated $519.9 million decrease in accruals for capital expenditures for the year ended December 31, 2015.
The use of cash for capital expenditures during the year ended December 31, 2015 was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to $34.0 million for 2015, primarily related to the disposition of certain non-producing leasehold acreage in Oklahoma for proceeds totaling $25.9 million.
For 2016, we currently expect our cash flows used in investing activities will be significantly lower than 2015 levels due to our decision to reduce our planned drilling activity for 2016 in response to the continued decrease in crude oil prices in late 2015 and early 2016. Our capital expenditures for 2016 are budgeted to be $920 million.
Cash flows from financing activities
Net cash provided by financing activities for the year ended December 31, 2015 totaled $1.19 billion, primarily resulting from net borrowings of $688 million on our revolving credit facility and $500 million of proceeds received from a new three-year term loan entered into in November 2015. Our 2015 operating cash flows were adversely impacted by decreased commodity prices, leading to an increase in credit facility borrowings incurred for the payment of amounts owed in connection with our 2014 drilling program and to fund a portion of our 2015 drilling program.

Net cash provided by financing activities for the year ended December 31, 2014 totaled $1.23 billion, primarily resulting from the receipt of $1.68 billion of net proceeds from the issuance of $1.0 billion of 3.8% Senior Notes due 2024 and $700 million of 4.9% Senior Notes due 2044 in May 2014, partially offset by net repayments of $110 million on our revolving credit facility and the July 2014 redemption of our 8.25% Senior Notes due 2019 for $317.5 million.

The level of credit facility borrowings we incurred in 2015 is not expected to continue in 2016. We are seeking to generally balance our 2016 capital expenditures with cash flows, which we expect will result in significantly reduced

capital spending and credit facility borrowings in 2016 compared to 2015.
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 2016 capital expenditures budget is reflective of the depressed commodity price environment and 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.

If cash flows are materially impacted by a further 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. On November 4, 2015 we refinanced $500 million of then outstanding credit facility borrowings into a new three-year term loan, and we may choose to access the capital markets for additional financing or capital to take advantage of business opportunities that may arise if such financing can be arranged on favorable terms. Additionally, we may choose to sell assets to obtain funding for our operations and capital program.

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 finance 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 or sell assets. 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

We have an unsecured credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $2.75 billion, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. 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 February 19, 2016, we had approximately $1.9 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. Borrowings bear interest at market-based interest rates plus a margin that is 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, such as the recent downgrades by S&P and Moody's that occurred in February 2016, do not trigger a reduction in our current credit facility commitments, nor do such actions trigger a security requirement or change in covenants. The recent downgrades of our credit rating will, however, trigger a 0.250% increase in our credit facility's interest rate and a 0.075% increase in the rate of commitment fees paid on unused borrowing availability under our credit facility.

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 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 (total debt 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, 2015 and expect to maintain compliance for at least the next 12 months. At December 31, 2015, our consolidated net debt to total capitalization ratio, as defined in the credit facility as amended, was 0.58 to 1.00. As we are focused on balancing our 2016 capital spending with cash flows to minimize new borrowings, we do not believe the 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, 2015, our total debt would have needed to independently increase by approximately $2.6 billion, or 36%, above existing levels 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 $1.4 billion, or 30%, below existing levels at December 31, 2015 (excluding the after-tax impact of any non-cash impairment charges) 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 significant portion of the Company's Northwest Cana natural gas properties. Pursuant to the agreement SK will fund, or carry, 50% of our drilling and completion costs attributable to an area of mutual interest within our Northwest Cana properties until approximately $270 million has been expended by SK on our behalf. As of December 31, 2015, approximately $200 million of the carry had yet to be realized and is expected to be realized over the next four years.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $5.8 billion at December 31, 2015. We have no near-term senior note maturities, with our earliest scheduled maturity being our $200 million of 2020 Notes due in October 2020. 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, see 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, 2015 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, such as the recent downgrades by S&P and Moody's that occurred in February 2016, do not trigger additional senior note covenants that are more restrictive than the existing covenants at December 31, 2015.

Two of our subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, 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.

Term loan

In November 2015, we entered into a $500 million unsecured term loan that matures in full in November 2018 and bears interest at variable market-based interest rates plus a margin that is based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. Downgrades or other negative rating actions with respect to our credit rating, such as the recent downgrades that occurred in February 2016, do not trigger a security requirement or change in covenants for the term loan. The recent downgrades of our credit rating will, however, trigger a 0.125% increase in our term loan's interest rate.

The covenant requirements in the three-year term loan are consistent with the covenants in our revolving credit facility, including the requirement that we maintain a consolidated net debt to total capitalization ratio of no greater than 0.65 to 1.0. We were in compliance with the three-year term loan's covenants at December 31, 2015 and expect to maintain compliance for at least the next 12 months.

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, 2015, we invested approximately $2.5 billion in our capital program, excluding $61.0 million of unbudgeted acquisitions, excluding $519.9 million of capital costs associated with decreased accruals for capital expenditures, and including $4.0 million of seismic costs. Our capital expenditures budget for 2015 was $2.7 billion excluding unbudgeted acquisitions. Our 2015 capital expenditures were allocated as follows by quarter:

In millions	1Q 2015	2Q 2015	3Q 2015	4Q 2015	YTD 2015
Exploration and development drilling	$914.2	$518.3	$477.8	$343.6	$2,253.9
Land costs	27.1	19.9	28.3	32.8	108.1
Capital facilities, workovers and other corporate assets	40.9	45.1	33.8	17.5	137.3
Seismic	1.6	2.2	0.1	0.1	4.0
Capital expenditures, excluding acquisitions	$983.8	$585.5	$540.0	$394.0	$2,503.3
Acquisitions of producing properties	0.1	0.4	—	0.1	0.6
Acquisitions of non-producing properties	36.7	6.0	—	17.7	60.4
Total acquisitions	36.8	6.4	—	17.8	61.0
Total capital expenditures	$1,020.6	$591.9	$540.0	$411.8	$2,564.3

In January 2016, our Board of Directors approved a 2016 capital expenditures budget of $920 million excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$784
Land costs	78
Capital facilities, workovers and other corporate assets	55
Seismic	3
Total 2016 capital budget, excluding acquisitions	$920

Our planned non-acquisition capital spending for 2016 has been set based on an expectation of available cash flows and is designed to target capital expenditures and cash flows being relatively balanced for 2016, with any cash flow deficiencies being funded by borrowings under our revolving credit facility.

For 2016, we plan to operate an average of approximately 19 drilling rigs for the year. We expect to spend 35% of our 2016 capital expenditures in North Dakota Bakken and 28% in SCOOP. Other key investment areas will be the STACK play, with 15% of capital expenditures, and our joint development area in Northwest Cana, with 7% of capital expenditures. The remaining 15% of our 2016 budget will target other capital expenditures such as routine leasing and renewals, work-overs, and facilities.

Our rig activity 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 results, the availability of drilling rigs and other services and equipment, the availability of transportation 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 continue to scale back our spending should commodity prices decrease further. Conversely, an increase in commodity prices 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, 2015:

	Payments due by period				
In thousands	Total	Less than 1 year (2016)	Years 2 and 3 (2017-2018)	Years 4 and 5 (2019-2020)	More than 5 years
Arising from arrangements on the balance sheet:					
Credit facility borrowings	$853,000	$ —	$—	$ 853,000	$—
Term loan	500,000	—	500,000	—	—
Senior Notes (1)	5,800,000	—	—	200,000	5,600,000
Note payable (2)	14,379	2,144	4,500	4,795	2,940
Interest payments (3)	2,817,452	308,236	614,747	572,360	1,322,109
Asset retirement obligations (4)	102,909	1,658	13,187	600	87,464
Arising from arrangements not on balance sheet: (5)					
Operating leases and other (6)	26,430	9,197	10,838	3,289	3,106
Drilling rig commitments (7)	421,564	199,763	197,705	24,096	—
Pipeline transportation commitments (8)	1,005,094	214,734	419,284	201,290	169,786
Fuel purchase commitment (9)	30,845	30,845	—	—	—
Total contractual obligations	$11,571,673	$ 766,577	$1,760,261	$ 1,859,430	$7,185,405

(1) Amounts represent scheduled maturities of our senior note obligations at December 31, 2015 and do not reflect any discount or premium at which the senior notes were issued. 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 $22 million borrowed in February 2012 under a 10-year amortizing note payable secured by the Company’s corporate office building in Oklahoma City, Oklahoma. 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 and three-year term loan borrowings outstanding at December 31, 2015 and assumes the actual weighted average interest rates on our revolving credit facility borrowings and three-year term loan of 1.9% and 1.8%, respectively, at December 31, 2015 continue through the respective maturity dates of the arrangements.

(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 leases for electric infrastructure, office equipment, communication towers, tanks for storage of hydraulic fracturing fluids, sponsorship agreements, and purchase obligations mainly related to software services.

(7) Amounts represent commitments under drilling rig contracts with various terms extending to year-end 2019 to ensure rig availability in our key operating areas.

(8) We have entered into firm transportation commitments to guarantee pipeline access capacity on operational crude oil and natural gas pipelines in order to move our production to market and to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. These commitments require us to pay per-unit transportation charges regardless of the amount of pipeline 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.

(9) We have entered into a forward purchase commitment with a third party to purchase specified quantities of diesel fuel at specified prices for use in our drilling operations. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies for additional discussion.

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 fields. 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, 2015, 2014, and 2013, our proved reserves were revised downward from prior years' reports by approximately 297.2 MMBoe, 107.9 MMBoe, and 96.1 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. 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, 2015, our proved reserves totaled 1,226 MMBoe as determined using 12-month average prices of $50.28 per barrel for crude oil and $2.58 per MMBtu for natural gas. Crude oil prices existing in February 2016 are significantly lower than the 2015 average price used to determine our year-end proved reserves. Holding all other factors constant, if crude oil prices used in our year-end reserve estimates were decreased by $15.00 per barrel, thereby approximating the pricing environment existing in February 2016, our proved reserves at December 31, 2015 could decrease by approximately 146 MMBoe, or 12%. If the proved reserves used in our DD&A calculations had been lower by 12% across all fields throughout 2015, our DD&A expense for 2015 would have increased by an estimated $235 million, or 13%. 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 a 12% revision in reserves cannot be predicted with certainty and may result in a change that is greater or less than 13%.

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.

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 our future crude oil and natural gas production. 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 our collars and written call options require 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 derivative fair value calculations to changes in forward commodity 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. Estimated future net cash flows associated with risk-adjusted probable and possible reserves may be taken into consideration when determining 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 \$138.9 million for 2015, of which \$27.5 million was recognized in the fourth quarter. Commodity price assumptions used for the year-end December 31, 2015 impairment calculations were based on publicly available average annual forward commodity strip prices through year-end 2020 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, 2015, the forward commodity strip prices for the year 2020 used in our fourth quarter impairment calculations averaged $53.80 per barrel for crude oil and $3.18 per Mcf for natural gas. Forward crude oil strip prices existing in February 2016 are lower than the year-end 2015 crude oil strip prices. If forward crude oil prices remain at current levels for an extended period or decline further, 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, 2015, 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 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. However, as is customary in the crude oil and natural gas industry, we have various contractual commitments not reflected in the consolidated balance sheets as shown under Part II, Item 7. Management's

Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations.

Pending Legislative and Regulatory Initiatives

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.

Inflation

In recent years prior to 2015 we experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to increases in drilling activity and competitive pressures resulting from attractive crude oil prices. However, in 2015 certain service and equipment costs decreased below 2014 levels as service providers reduced their costs in response to the significant decrease in commodity prices. If the existing commodity price environment persists or worsens in 2016 our industry may experience an additional decrease in certain service and equipment costs. However, inflationary pressures may return in the future if commodity prices recover from current levels.

Non-GAAP Financial Measures

EBITDAX

We present EBITDAX throughout this Form 10-K, which is a non-GAAP financial measure. We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. Further, we believe EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income (loss) and operating cash flows in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) or operating cash flows as determined in accordance with U.S. GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

	Year Ended December 31,				
In thousands	2015	2014	2013	2012	2011
Net income (loss)	$(353,668)	$977,341	$764,219	$739,385	$429,072
Interest expense	313,079	283,928	235,275	140,708	76,722
Provision (benefit) for income taxes	(181,417)	584,697	448,830	415,811	258,373
Depreciation, depletion, amortization and accretion	1,749,056	1,358,669	965,645	692,118	390,899
Property impairments	402,131	616,888	220,508	122,274	108,458
Exploration expenses	19,413	50,067	34,947	23,507	27,920
Impact from derivative instruments:					
Total (gain) loss on derivatives, net	(91,085)	(559,759)	191,751	(154,016)	30,049
Total cash (paid) received on derivatives, net	69,553	385,350	(61,555)	(45,721)	(34,106)
Non-cash (gain) loss on derivatives, net	(21,532)	(174,409)	130,196	(199,737)	(4,057)
Non-cash equity compensation	51,834	54,353	39,890	29,057	16,572
Loss on extinguishment of debt	—	24,517	—	—	—

EBITDAX	$1,978,896	$3,776,051	$2,839,510	$1,963,123	$1,303,959

The following table provides a reconciliation of our net cash provided by operating activities to EBITDAX for the periods presented.

	Year Ended December 31,				
In thousands	2015	2014	2013	2012	2011
Net cash provided by operating activities	$1,857,101	$3,355,715	$2,563,295	$1,632,065	$1,067,915
Current income tax provision	24	20	6,209	10,517	13,170
Interest expense	313,079	283,928	235,275	140,708	76,722
Exploration expenses, excluding dry hole costs	11,032	26,388	25,597	22,740	19,971
Gain on sale of assets, net	23,149	600	88	136,047	20,838
Excess tax benefit from stock-based compensation	13,177	—	—	15,618	—
Other, net	(10,044)	(17,279)	(1,829)	(7,587)	(4,606)
Changes in assets and liabilities	(228,622)	126,679	10,875	13,015	109,949
EBITDAX	$1,978,896	$3,776,051	$2,839,510	$1,963,123	$1,303,959

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, 2015, our PV-10 totaled approximately $8.0 billion. The Standardized Measure of our discounted future net cash flows was approximately $6.5 billion at December 31, 2015, representing a $1.5 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 year ended December 31, 2015 and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $535 million for each $10.00 per barrel change in crude oil prices and $164 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by these market fluctuations, 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 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 favorable 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. Our crude oil production and sales for 2016 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

Changes in natural gas prices during the year ended December 31, 2015 had an overall favorable impact on the fair value of our derivative instruments. For the year ended December 31, 2015, we recognized cash gains on derivatives of $69.6 million and non-cash mark-to-market gains on derivatives of $21.5 million.

The fair value of our natural gas derivative instruments at December 31, 2015 was a net asset of $101 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 derivative valuation to a net liability of approximately $101 million at December 31, 2015. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $302 million at December 31, 2015.

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, 2015.

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 ($379 million in receivables at December 31, 2015), our joint interest receivables ($232 million at December 31, 2015), and counterparty credit risk associated with our derivative instrument receivables ($108 million at December 31, 2015).

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 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 $50 million at December 31, 2015, 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 our co-owners 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 and three-year term loan. 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 an aggregate of $1.33 billion of variable rate borrowings outstanding on our revolving credit facility and three-year term loan at February 19, 2016. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $13.3 million per year and an $8.2 million decrease in net income per year.

The following table presents our debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2015:

In thousands	2016	2017	2018	2019	2020	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	$—	$—	$—	$—	$200,000	$5,600,000	$5,800,000
Weighted-average interest rate	—	—	—	—	7.4 %	4.8 %	4.9 %
Note payable:							
Principal amount	$2,144	$2,214	$2,286	$2,360	$2,435	$2,940	$14,379
Interest rate	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %
Variable rate debt:							
Credit facility:							
Principal amount	$—	$—	$—	$853,000	$—	$—	$853,000
Weighted-average interest rate	—	—	—	1.9 %	—	—	1.9 %
Term loan:							
Principal amount	$—	$—	$500,000	$—	$—	$—	$500,000
Interest rate	—	—	1.8 %	—	—	—	1.8 %

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

Changes in interest rates affect the amounts we pay on borrowings under our revolving credit facility and three-year term loan. Such borrowings bear interest at market-based interest rates plus a margin that is based on the terms of the borrowing and the credit ratings assigned to our senior, unsecured, long-term indebtedness. In February 2016, our corporate credit rating was downgraded by S&P and Moody's in response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions. These downgrades will cause the interest rates on our revolving credit facility borrowings and three-year term loan to increase by 0.250% and 0.125%, respectively. 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. However, changes in interest rates do affect the fair values of our senior notes and note payable.

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.
We have audited the accompanying consolidated balance sheets of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the "Company") as of December 31, 2015 and 2014, and 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, 2015. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.
We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.
In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Continental Resources, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.
As discussed in Note 1 to the consolidated financial statements, the Company adopted new accounting guidance in 2015 and 2014, related to the presentation of debt issuance costs. Also, as discussed in Note 1 to the consolidated financial statements, the Company adopted new accounting guidance in 2015 and 2014, related to the presentation of deferred income taxes.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2015, 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 24, 2016 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 24, 2016

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31,	
In thousands, except par values and share data	2015	2014
Assets		
Current assets:		
Cash and cash equivalents	$11,463	$24,381
Receivables:		
Crude oil and natural gas sales	378,622	552,476
Affiliated parties	122	13,360
Joint interest and other, net	232,293	567,476
Derivative assets	93,922	52,423
Inventories	94,151	102,179
Prepaid taxes	94	63,266
Prepaid expenses and other	11,672	14,040
Total current assets	822,339	1,389,601
Net property and equipment, based on successful efforts method of accounting	14,063,328	13,635,852
Noncurrent derivative assets	14,560	31,992
Other noncurrent assets	19,581	18,588
Total assets	$14,919,808	$15,076,033
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable trade	$553,285	$1,263,724
Revenues and royalties payable	187,000	272,755
Payables to affiliated parties	69	7,305
Accrued liabilities and other	176,947	259,157
Derivative liabilities	3,583	1,645
Current portion of long-term debt	2,144	2,078
Total current liabilities	923,028	1,806,664
Long-term debt, net of current portion	7,115,644	5,926,800
Other noncurrent liabilities:		
Deferred income tax liabilities, net	2,090,228	2,286,796
Asset retirement obligations, net of current portion	101,251	75,462
Noncurrent derivative liabilities	3,706	3,109
Other noncurrent liabilities	17,051	9,358
Total other noncurrent liabilities	2,212,236	2,374,725
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; 372,959,080 shares issued and outstanding at December 31, 2015; 372,005,502 shares issued and outstanding at December 31, 2014	3,730	3,720
Additional paid-in capital	1,345,624	1,287,941
Accumulated other comprehensive loss	(3,354)	(385)
Retained earnings	3,322,900	3,676,568
Total shareholders' equity	4,668,900	4,967,844
Total liabilities and shareholders' equity	$14,919,808	$15,076,033

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	2015	2014	2013
Revenues:			
Crude oil and natural gas sales	$2,551,131	$4,107,894	$3,473,026
Crude oil and natural gas sales to affiliates	1,400	95,128	100,405
Gain (loss) on derivative instruments, net	91,085	559,759	(191,751)
Crude oil and natural gas service operations	36,551	38,837	40,127
Total revenues	2,680,167	4,801,618	3,421,807
Operating costs and expenses:			
Production expenses	347,243	347,349	280,789
Production expenses to affiliates	1,654	5,123	1,408
Production taxes and other expenses	200,637	349,760	298,787
Exploration expenses	19,413	50,067	34,947
Crude oil and natural gas service operations	17,337	21,871	29,665
Depreciation, depletion, amortization and accretion	1,749,056	1,358,669	965,645
Property impairments	402,131	616,888	220,508
General and administrative expenses	189,846	184,655	144,379
Gain on sale of assets, net	(23,149)	(600)	(88)
Total operating costs and expenses	2,904,168	2,933,782	1,976,040
Income (loss) from operations	(224,001)	1,867,836	1,445,767
Other income (expense):			
Interest expense	(313,079)	(283,928)	(235,275)
Loss on extinguishment of debt	—	(24,517)	—
Other	1,995	2,647	2,557
	(311,084)	(305,798)	(232,718)
Income (loss) before income taxes	(535,085)	1,562,038	1,213,049
Provision (benefit) for income taxes	(181,417)	584,697	448,830
Net income (loss)	$(353,668)	$977,341	$764,219
Basic net income (loss) per share	$(0.96)	$2.65	$2.08
Diluted net income (loss) per share	$(0.96)	$2.64	$2.07
Comprehensive income (loss):			
Net income (loss)	$(353,668)	$977,341	$764,219
Other comprehensive loss, net of tax			
Foreign currency translation adjustments	(2,969)	(385)	—
Total other comprehensive loss, net of tax	(2,969)	(385)	—
Comprehensive income (loss)	$(356,637)	$976,956	$764,219

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 loss	Retained earnings	Total shareholders' equity
Balance at December 31, 2012	371,209,362	$ 3,712	$ 1,224,979	$ —	$ 1,935,008	$ 3,163,699
Net income	—	—	—	—	764,219	764,219
Stock-based compensation	—	—	39,886	—	—	39,886
Restricted stock:						
Granted	522,518	5	—	—	—	5
Repurchased and canceled	(277,050)	(3)	(14,687)	—	—	(14,690)
Forfeited	(137,512)	(1)	—	—	—	(1)
Balance at December 31, 2013	371,317,318	$ 3,713	$ 1,250,178	$ —	$ 2,699,227	$ 3,953,118
Net income	—	—	—	—	977,341	977,341
Other comprehensive loss, net of tax	—	—	—	(385)	—	(385)
Stock-based compensation	—	—	54,343	—	—	54,343
Restricted stock:						
Granted	1,424,764	14	—	—	—	14
Repurchased and canceled	(283,434)	(3)	(16,580)	—	—	(16,583)
Forfeited	(453,146)	(4)	—	—	—	(4)
Balance at December 31, 2014	372,005,502	$ 3,720	$ 1,287,941	$ (385)	$ 3,676,568	$ 4,967,844
Net income (loss)	—	—	—	—	(353,668)	(353,668)
Other comprehensive loss, net of tax	—	—	—	(2,969)	—	(2,969)
Stock-based compensation	—	—	51,817	—	—	51,817
Excess 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

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, 2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$(353,668)	$977,341	$764,219
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	1,746,454	1,368,311	965,437
Property impairments	402,131	616,888	220,508
Non-cash (gain) loss on derivatives, net	(21,532)	(174,409)	130,196
Stock-based compensation	51,834	54,353	39,890
Provision (benefit) for deferred income taxes	(181,441)	584,677	442,621
Excess tax benefit from stock-based compensation	(13,177)	—	—
Dry hole costs	8,381	23,679	9,350
Gain on sale of assets, net	(23,149)	(600)	(88)
Loss on extinguishment of debt	—	24,517	—
Other, net	12,646	7,637	2,037
Changes in assets and liabilities:			
Accounts receivable	524,973	(129,634)	(166,138)
Inventories	7,997	(65,919)	(7,697)
Other current assets	65,493	(57,489)	(11,537)
Accounts payable trade	(201,434)	85,540	107,250
Revenues and royalties payable	(85,754)	(18,022)	28,401
Accrued liabilities and other	(84,056)	58,880	44,260
Other noncurrent assets and liabilities	1,403	(35)	(5,414)
Net cash provided by operating activities	1,857,101	3,355,715	2,563,295
Cash flows from investing activities:			
Exploration and development	(3,042,747)	(4,604,468)	(3,660,773)
Purchase of producing crude oil and natural gas properties	(557)	(48,917)	(16,604)
Purchase of other property and equipment	(36,951)	(63,402)	(62,054)
Proceeds from sale of assets and other	34,008	129,388	28,420
Net cash used in investing activities	(3,046,247)	(4,587,399)	(3,711,011)
Cash flows from financing activities:			
Credit facility borrowings	2,001,000	1,695,000	970,000
Repayment of credit facility	(1,313,000)	(1,805,000)	(1,290,000)
Proceeds from issuance of Senior Notes	—	1,681,834	1,479,375
Redemption of Senior Notes	—	(300,000)	—
Premium on redemption of Senior Notes	—	(17,497)	—
Proceeds from other debt	500,000	—	—
Repayment of other debt	(2,078)	(2,013)	(1,951)
Debt issuance costs	(4,597)	(8,026)	(2,265)
Repurchase of restricted stock for tax withholdings	(7,313)	(16,583)	(14,690)
Excess tax benefit from stock-based compensation	13,177	—	—
Net cash provided by financing activities	1,187,189	1,227,715	1,140,469
Effect of exchange rate changes on cash	(10,961)	(132)	—
Net change in cash and cash equivalents	(12,918)	(4,101)	(7,247)

Cash and cash equivalents at beginning of period	24,381	28,482	35,729
Cash and cash equivalents at end of period	$11,463	$24,381	$28,482

The accompanying notes are an integral part of these consolidated financial statements.
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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 Kansas and west of the Mississippi River including various plays in the SCOOP (South Central Oklahoma Oil Province), STACK (Sooner Trend Anadarko Canadian Kingfisher), Northwest Cana and Arkoma Woodford areas of Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River with no current drilling or production operations.
A substantial portion of the Company’s operations are concentrated in the North region, with that region comprising approximately 68% of the Company’s crude oil and natural gas production and approximately 77% of its crude oil and natural gas revenues for the year ended December 31, 2015. 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, 2015, approximately 58% of the Company’s estimated proved reserves were located in the North region. In recent years, the Company has significantly expanded its activity in the South region with its discovery of the SCOOP play and its increased activity in the Northwest Cana and STACK plays. The South region comprised approximately 32% of the Company's crude oil and natural gas production, 23% of its crude oil and natural gas revenues, and 42% of its estimated proved reserves at December 31, 2015.
The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the year ended December 31, 2015, crude oil accounted for approximately 66% of the Company’s total production and approximately 85% of its crude oil and natural gas revenues. Crude oil represents approximately 57% of the Company's estimated proved reserves as of December 31, 2015.
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 period. Actual results may differ from those estimates. The most significant of the estimates and assumptions that affect reported results are the 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, 2015 and 2014 were not material.

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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, 2015, the Company had cash deposits in excess of federally insured amounts of approximately $10.7 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.

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, 2015, sales to the Company's largest purchaser accounted for approximately 11% of its total crude oil and natural gas sales. No other purchasers accounted for more than 10% of the Company's total crude oil and natural gas sales for 2015. 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 at the lower of cost or market, with cost determined primarily using a weighted average cost method applied to specific classes of inventory items.

The components of inventory as of December 31, 2015 and 2014 consisted of the following:

	December 31,	
In thousands	2015	2014
Tubular goods and equipment	$15,633	$15,659
Crude oil	78,518	86,520
Total	$94,151	$102,179

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 labor costs to operate the Company's properties, repairs and maintenance, waste water disposal 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 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 systems	15-30
Storage tanks	10-30
Office and computer equipment, software, furniture and fixtures	3-10
Enterprise resource planning software	25
Buildings and improvements	10-40

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.

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

The Company’s primary asset retirement obligations relate to future plugging and abandonment costs on its crude oil and natural gas properties and related facilities disposal. The following table summarizes the changes in the Company’s future abandonment liabilities from January 1, 2013 through December 31, 2015:

In thousands	2015	2014	2013
Asset retirement obligations at January 1	$76,708	$55,787	$47,171
Accretion expense	4,740	3,366	2,767
Revisions (1)	15,068	9,916	2,826
Plus: Additions for new assets	7,404	9,022	6,009
Less: Plugging costs and sold assets	(1,011)	(1,383)	(2,986)
Total asset retirement obligations at December 31	$102,909	$76,708	$55,787
Less: Current portion of asset retirement obligations at December 31 (2)	1,658	1,246	1,434
Non-current portion of asset retirement obligations at December 31	$101,251	$75,462	$54,353

(1) Revisions for the years ended December 31, 2015 and 2014 primarily represent an increase in the present value of liabilities from an acceleration in the estimated timing of abandonment prompted by decreases in commodity prices in 2015 and 2014 which shortened the economic lives of certain producing properties.
(2) Balance is included in the caption "Accrued liabilities and other" in the consolidated balance sheets.

As of December 31, 2015 and 2014, net property and equipment on the consolidated balance sheets included $87.5 million and $64.7 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 three-year term loan, 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 capitalized costs of $71.8 million and $76.1 million (net of accumulated amortization of $47.0 million and $38.1 million) relating to its long-term debt at December 31, 2015 and 2014, respectively. See the subsequent heading titled New accounting pronouncements for a discussion of the presentation of these costs on the consolidated balance sheets.

For the years ended December 31, 2015, 2014 and 2013, the Company recognized amortization expense associated with capitalized debt issuance costs of $8.9 million, $9.3 million and $8.6 million, respectively, which are reflected in “Interest expense” in 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) under the caption "Gain (loss) on derivative instruments, net."

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, 2015 and 2014.

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. 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 $13.5 million and $4.4 million for the years ended December 31, 2015 and 2014, 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. Diluted net income (loss) 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, 2015, 2014 and 2013.

	Year ended December 31,		
In thousands, except per share data	2015	2014	2013
Income (loss) (numerator):			
Net income (loss) - basic and diluted	$(353,668)	$977,341	$764,219
Weighted average shares (denominator):			
Weighted average shares - basic	369,540	368,829	368,150
Non-vested restricted stock (1)	—	1,929	1,548
Weighted average shares - diluted	369,540	370,758	369,698
Net income (loss) per share:			
Basic	$(0.96)	$2.65	$2.08
Diluted	$(0.96)	$2.64	$2.07

(1) During the year ended December 31, 2015, the Company had a net loss and therefore the potential dilutive effect of approximately 1,567,000 weighted average restricted shares were not included in the calculation of diluted net loss per share for 2015 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 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 loss" within shareholders' equity on the consolidated balance sheets.

New accounting pronouncements

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). The new standard requires debt issuance costs related to a recognized term debt liability, such as the Company's senior notes, three-year term loan and note payable, be presented in the balance sheet as a direct deduction from the carrying amount of that term debt liability, consistent with the presentation of a debt discount. Under previous guidance, debt issuance costs were required to be presented in the balance sheet as an asset. The new standard does not affect the existing recognition and measurement guidance for debt issuance costs. The new standard is effective for annual and interim periods beginning after December 15, 2015, with early adoption permitted.

The Company early adopted ASU 2015-03 as of June 30, 2015 on a retrospective basis to all prior balance sheet periods presented. As a result of the adoption, the Company reclassified unamortized debt issuance costs associated with its senior notes and note payable, which totaled $65.7 million and $69.0 million as of June 30, 2015 and December 31, 2014, respectively, from "Other noncurrent assets" to a reduction of "Long-term debt, net of current portion" on the consolidated balance sheets. Unamortized debt issuance costs reflected as a reduction of long-term debt subsequently totaled $64.0 million as of December 31, 2015, inclusive of costs incurred upon execution of the Company's new term loan in November 2015 as discussed in Note 7. Long-Term Debt. Adoption of ASU 2015-03 had no impact on the Company's current and previously reported shareholders' equity, results of operations, or cash flows. The December 31, 2014 carrying amounts for the Company's senior notes and note payable presented throughout this report on Form 10-K have been adjusted to reflect the retroactive adoption of ASU 2015-03. Unamortized debt issuance costs associated with the Company's revolving credit facility, which amounted to $7.8 million and $7.0 million as of December 31, 2015 and 2014, respectively, were not reclassified and remain reflected in "Other noncurrent assets" on the consolidated balance sheets.

In November 2015, the FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes, which requires entities with a classified balance sheet to present all deferred tax assets and deferred tax liabilities as noncurrent instead of separating deferred taxes into current and noncurrent amounts. The standard will be effective for public companies for annual and interim periods beginning after December 15, 2016, with early adoption permitted. The Company early adopted ASU 2015-17 as of December 31, 2015 on a retrospective basis to all prior balance sheet periods presented. As a result of the adoption, the Company reclassified $36.2 million and $145.3 million as of December 31, 2015 and 2014, respectively, from "Accrued liabilities and other" to “Deferred income tax liabilities, net” on the consolidated balance sheets. Adoption of ASU 2015-17 had no impact on the Company's current and previously reported shareholders' equity, results of operations, or cash flows. The affected prior period deferred income tax account balances presented throughout this report on Form 10-K have been adjusted to reflect the retroactive adoption of ASU 2015-17.

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	2015	2014	2013
Supplemental cash flow information:			
Cash paid for interest	$301,743	$267,384	$209,815
Cash paid for income taxes	30	53,457	29,017
Cash received for income tax refunds	61,403	7	174
Non-cash investing activities:			
Increase (decrease) in accrued capital expenditures	(519,949)	290,782	89,482
Asset retirement obligation additions and revisions, net	22,472	18,938	8,835

Note 3. Net Property and Equipment

Net property and equipment includes the following at December 31, 2015 and 2014:

In thousands	December 31, 2015	2014
Proved crude oil and natural gas properties	$19,520,724	$17,045,967
Unproved crude oil and natural gas properties	682,988	966,080
Service properties, equipment and other	307,059	274,584
Total property and equipment	20,510,771	18,286,631
Accumulated depreciation, depletion and amortization	(6,447,443)	(4,650,779)
Net property and equipment	$14,063,328	$13,635,852

Note 4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2015 and 2014:

In thousands	December 31, 2015	2014
Prepaid advances from joint interest owners	$49,917	$115,687
Accrued compensation	40,060	39,848
Accrued production taxes, ad valorem taxes and other non-income taxes	21,678	36,550
Accrued interest	62,058	60,861
Current portion of asset retirement obligations	1,658	1,246
Other	1,576	4,965
Accrued liabilities and other	$176,947	$259,157

Note 5. Derivative Instruments

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 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) under the caption “Gain (loss) on derivative instruments, net.”

The Company may utilize swap and collar derivative contracts to economically hedge against the variability in cash flows associated with the sale of future 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.

With respect to a 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 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.

The Company's derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Inter-Continental Exchange ("ICE") pricing for Brent crude oil and natural gas derivative settlements based on NYMEX Henry Hub pricing. 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.

At December 31, 2015, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below. The hedged volumes reflected below represent an aggregation of multiple derivative contracts that have varying durations and may not be realized on a ratable basis over a calendar year.

Crude Oil - ICE Brent

Period and Type of Contract	Bbls	Ceiling Price
January 2016 - December 2016		
Written call options - ICE Brent (1)	1,464,000	$107.70

(1) Written call options represent the ceiling positions remaining from the Company's previous crude oil collar contracts. The floor positions of the collars were liquidated in the fourth quarter of 2014. For these written call options, the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price.

Natural Gas - Henry Hub		Swaps	Floors		Ceilings	
Period and Type of Contract	MMBtus	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
January 2016 - December 2016						
Swaps - Henry Hub	133,710,000	$3.17				
January 2017 - December 2017						
Swaps - Henry Hub	25,550,000	$3.35				
Collars - Henry Hub	65,700,000		$2.40 - $3.00	$2.47	$2.92 - $3.88	$3.08

Derivative gains and losses

The following table presents cash settlements on matured or liquidated derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented. Cash receipts and payments below reflect proceeds received upon early liquidation of derivative positions and gains or losses 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 and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured or were liquidated during the period.

	Year ended December 31,		
In thousands	2015	2014	2013
Cash received (paid) on derivatives:			
Crude oil fixed price swaps (1)	$—	$331,591	$(54,289)
Crude oil collars (1)	—	65,310	(16,867)
Natural gas fixed price swaps	39,670	(11,551)	9,601
Natural gas collars	29,883	—	—
Cash received (paid) on derivatives, net	69,553	385,350	(61,555)
Non-cash gain (loss) on derivatives:			
Crude oil fixed price swaps	—	84,792	(117,580)
Crude oil collars	—	1,121	(8,587)
Crude oil written call options	4,715	3,981	—
Natural gas fixed price swaps	41,828	62,699	(4,029)
Natural gas collars	(25,011)	21,816	—

Non-cash gain (loss) on derivatives, net	21,532	174,409	(130,196)
Gain (loss) on derivative instruments, net	$91,085	$559,759	$(191,751)

(1) Net cash receipts for crude oil swaps and collars for the year ended December 31, 2014 include $433 million of proceeds received from crude oil derivative contracts that were settled in the fourth quarter of 2014 prior to their contractual maturities. Of the proceeds, $373 million related to crude oil swap liquidations and $60 million related to crude oil collar liquidations.

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". 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 present the gross amounts of recognized derivative assets and liabilities, 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	2015		2014	
Commodity derivative assets:				
Gross amounts of recognized assets	$120,385		$84,431	
Gross amounts offset on balance sheet	(11,903	)	(16	)
Net amounts of assets on balance sheet	108,482		84,415	
Commodity derivative liabilities:				
Gross amounts of recognized liabilities	(19,192	)	(4,770	)
Gross amounts offset on balance sheet	11,903		16	
Net amounts of liabilities on balance sheet	$(7,289	)	$(4,754	)

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	2015		2014	
Derivative assets	$93,922		$52,423	
Noncurrent derivative assets	14,560		31,992	
Net amounts of assets on balance sheet	108,482		84,415	
Derivative liabilities	(3,583	)	(1,645	)
Noncurrent derivative liabilities	(3,706	)	(3,109	)
Net amounts of liabilities on balance sheet	(7,289	)	(4,754	)
Total derivative assets, net	$101,193		$79,661	

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 that are 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 that are 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.

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 fixed price swaps, 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 fixed price swaps are calculated mainly using significant observable inputs (Level 2). Calculation of the fair values of collars and written call options 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, 2015 and 2014.

	Fair value measurements at December 31, 2015 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$104,426	$—	$104,426
Collars	—	(3,195)	—	(3,195)
Written call options	—	(38)	—	(38)
Total	$—	$101,193	$—	$101,193

	Fair value measurements at December 31, 2014 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$62,599	$—	$62,599
Collars	—	21,816	—	21,816
Written call options	—	(4,754)	$—	(4,754)
Total	$—	$79,661	$—	$79,661

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. 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, 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 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 swap prices through 2020 (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 0 to 34 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.

Impairments of proved properties amounted to $138.9 million for the year ended December 31, 2015 resulting from declines in commodity prices that indicated the carrying amounts for certain fields were not recoverable. The 2015 impairments reflect fair value adjustments primarily concentrated in an emerging area with minimal production and costly reserve additions ($42.5 million), the Medicine Pole Hills units ($32.5 million), the Buffalo Red River units ($26.3 million), non-Bakken areas of North Dakota and Montana ($8.2 million), Wyoming properties ($17.9 million), and various legacy areas in the South region ($11.4 million). The impaired properties were written down to their estimated fair value totaling approximately $59.9 million.

Certain unproved crude oil and natural gas properties were impaired during the years ended December 31, 2015, 2014, and 2013, 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	2015	2014	2013
Proved property impairments	$138,878	$324,302	$51,805
Unproved property impairments	263,253	292,586	168,703
Total	$402,131	$616,888	$220,508

Financial instruments not recorded at fair value

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

	December 31, 2015		December 31, 2014	
In thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Credit facility	$853,000	$853,000	$165,000	$165,000
Term loan	498,274	500,000	—	—
Note payable	14,309	12,500	16,375	14,900
7.375% Senior Notes due 2020	196,574	179,200	195,997	213,000
7.125% Senior Notes due 2021	395,365	388,300	394,668	421,000
5% Senior Notes due 2022	1,996,831	1,480,400	1,996,507	1,857,900
4.5% Senior Notes due 2023	1,482,451	1,061,000	1,480,479	1,372,800
3.8% Senior Notes due 2024	989,932	700,300	988,940	868,700
4.9% Senior Notes due 2044	691,052	430,500	690,912	572,400

Total debt	$7,117,788	$5,605,200	$5,928,878	$5,485,700

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The fair values of 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.

The fair values of the 7.375% Senior Notes due 2020 (“2020 Notes”), the 7.125% Senior Notes due 2021 (“2021 Notes”), 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”), 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 $49.6 million and $52.6 million at December 31, 2015 and 2014, respectively, consists of the following. See Note 1. Organization and Summary of Significant Accounting Policies—New accounting pronouncements for a discussion of the impact on long-term debt from the Company's adoption of ASU 2015-03.

	December 31,	
In thousands	2015	2014
Credit facility	$853,000	$165,000
Term loan	498,274	—
Note payable	14,309	16,375
7.375% Senior Notes due 2020	196,574	195,997
7.125% Senior Notes due 2021	395,365	394,668
5% Senior Notes due 2022	1,996,831	1,996,507
4.5% Senior Notes due 2023	1,482,451	1,480,479
3.8% Senior Notes due 2024	989,932	988,940
4.9% Senior Notes due 2044	691,052	690,912
Total debt	7,117,788	5,928,878
Less: Current portion of long-term debt	2,144	2,078
Long-term debt, net of current portion	$7,115,644	$5,926,800

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, 2015, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders.

The Company had $853 million and $165 million of outstanding borrowings on its credit facility at December 31, 2015 and 2014, respectively. Borrowings bear interest at market-based interest rates plus a margin that is 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 borrowings at December 31, 2015 was 1.9%.

The Company had approximately $1.9 billion of borrowing availability on its credit facility at December 31, 2015 and incurred commitment fees based on its assigned credit rating at that date of 0.225% per annum of the daily average amount of unused borrowing availability under its 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 (total debt 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 this covenant at December 31, 2015.

Senior notes

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, 2015.

	2020 Notes	2021 Notes	2022 Notes	2023 Notes	2024 Notes	2044 Notes
Face value (in thousands)	$200,000	$400,000	$2,000,000	$1,500,000	$1,000,000	$700,000
Maturity date	Oct 1, 2020	April 1, 2021	Sep 15, 2022	April 15, 2023	June 1, 2024	June 1, 2044
Interest payment dates	April 1, Oct 1	April 1, Oct 1	March 15, Sep 15	April 15, Oct 15	June 1, Dec 1	June 1, Dec 1
Call premium redemption period (1)	Oct 1, 2015	April 1, 2016	March 15, 2017	—	—	—
Make-whole redemption period (2)	Oct 1, 2015	April 1, 2016	March 15, 2017	Jan 15, 2023	Mar 1, 2024	Dec 1, 2043

(1) On or after these dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series at the decreasing redemption prices specified in the respective senior note indentures (together, the "Indentures") plus any accrued and unpaid interest to the date of redemption.

(2) At any time prior to these 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 Indentures 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 others, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, and 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, 2015. Two of the Company's subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, 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.

2014 Redemption of Senior Notes

In July 2014, the Company redeemed its then outstanding 8.25% Senior Notes due 2019 ("2019 Notes") using a portion of the proceeds from the May 2014 issuances of 2024 Notes and 2044 Notes. The 2019 Notes were redeemed for $317.5 million, representing a make-whole amount calculated in accordance with the terms of the 2019 Notes and related indenture. The Company recognized a pre-tax loss of $24.5 million related to the redemption, which included the make-whole premium and the write-off of deferred financing costs and unaccreted debt discount 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, 2014.

Term loan

In November 2015, the Company borrowed $500 million under a three-year term loan agreement, the proceeds of which were used to repay a portion of the borrowings then outstanding on the Company's revolving credit facility. The term loan matures in full on November 4, 2018 and bears interest at a variable market-based interest rate plus a margin that is based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The interest rate on the term loan at December 31, 2015 was 1.8%.

The term loan 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 1.0, consistent with the covenant requirement in the Company's revolving credit facility. The Company was in compliance with this covenant at December 31, 2015.

Note payable

In February 2012, 20 Broadway Associates LLC, a 100% owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing note payable 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 $2.1 million is reflected as a current liability under the caption "Current portion of long-term debt" in the consolidated balance sheets at December 31, 2015.

Note 8. Income Taxes

The items comprising the provision (benefit) for income taxes are as follows for the periods presented:

	Year ended December 31,		
In thousands	2015	2014	2013
Current income tax provision:			
United States federal	$—	$—	$6,193
Various states	24	20	16
Total current income tax provision	24	20	6,209
Deferred income tax provision (benefit):			
United States federal	(140,578)	527,315	403,002
Various states	(40,863)	57,362	39,619
Total deferred income tax provision (benefit)	(181,441)	584,677	442,621
Total provision (benefit) for income taxes	$(181,417)	$584,697	$448,830

The provision (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,		
In thousands	2015	2014	2013
Expected income tax expense (benefit) based on US statutory tax rate of 35%	$(187,280)	$546,713	$424,567
State income taxes, net of federal benefit	(16,219)	42,169	25,838
Canadian valuation allowance	13,503	4,389	—
Effect of differing statutory tax rate in Canada	5,239	(1,900)	—
Other, net	3,340	(6,674)	(1,575)
Provision (benefit) for income taxes	$(181,417)	$584,697	$448,830

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The components of the Company's deferred tax assets and deferred tax liabilities as of December 31, 2015 and 2014 are reflected in the table below. As discussed in Note 1. Organization and Summary of Significant Accounting Policies—New accounting pronouncements, in November 2015 the FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes. This new standard requires that all deferred tax assets and deferred tax liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The new standard was early-adopted by the Company as of December 31, 2015 on a retrospective basis to all prior balance sheet periods presented. Accordingly, all deferred tax assets and deferred tax liabilities have been reflected as noncurrent and the Company reclassified $36.2 million and $145.3 million as of December 31, 2015 and 2014, respectively, from "Accrued liabilities and other" to "Deferred income tax liabilities, net" on the consolidated balance sheets.

In thousands	December 31, 2015	2014
Deferred tax assets		
United States net operating loss carryforwards	398,024	60,904
Canadian net operating loss carryforwards	17,892	4,899
Alternative minimum tax carryforwards	40,796	38,715
Equity compensation	32,910	22,255
Other	11,048	8,920
Total deferred tax assets	500,670	135,693
Canadian valuation allowance	(17,892)	(4,389)
Total deferred tax assets, net of valuation allowance	482,778	131,304
Deferred tax liabilities		
Property and equipment	(2,528,125)	(2,254,343)
Non-cash gains on derivatives	(38,452)	(30,269)
Gain on derivative liquidation	(4,158)	(132,356)
Other	(2,271)	(1,132)
Total deferred tax liabilities	(2,573,006)	(2,418,100)
Deferred income tax liabilities, net	$(2,090,228)	$(2,286,796)

As of December 31, 2015, the Company had federal and state net operating loss carryforwards of $865 million and $2.63 billion, respectively. The federal net operating loss carryforward will begin expiring in 2033. The Oklahoma net operating loss carryforward of $2.12 billion will begin to expire in 2027. The remainder of the state net operating loss carryforwards will begin expiring in 2017. The Company has alternative minimum tax credit carryforwards of $41 million that have no expiration date. 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 2012.

The Company recorded valuation allowances of $13.5 million and $4.4 million against Canadian deferred tax assets for the years ended December 31, 2015 and 2014, respectively, which resulted in a cumulative valuation allowance of $17.9 million as of December 31, 2015. 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 surface rentals, office equipment, communication towers, software services, and tanks for storage of hydraulic fracturing fluids. Lease payments associated with operating leases for the years ended December 31, 2015, 2014 and 2013 were $9.6 million, $8.0 million and $3.0 million, respectively, a portion of which was capitalized and/or billed to other interest owners. At December 31, 2015, the minimum future rental commitments under operating leases having lease terms in excess of one year are as follows:

In thousands	Total amount
2016	$3,348
2017	1,327
2018	979
2019	291
2020	210
Thereafter	3,105
Total obligations	$9,260

Note 10. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of December 31, 2015. The commitments under these arrangements are not recorded in the accompanying consolidated balance sheets.

Drilling commitments – As of December 31, 2015, the Company had drilling rig contracts with various terms extending to year-end 2019 to ensure rig availability in its key operating areas. Future commitments as of December 31, 2015 total approximately $422 million, of which $200 million is expected to be incurred in 2016, $136 million in 2017, $62 million in 2018, and $24 million in 2019.

Pipeline transportation commitments – The Company has entered into firm transportation commitments to guarantee pipeline access capacity on operational crude oil and natural gas pipelines. The commitments, which have varying terms extending as far as 2027, require the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of December 31, 2015 under the operational pipeline transportation arrangements amount to approximately $1.0 billion, of which $215 million is expected to be incurred in 2016, $212 million in 2017, $207 million in 2018, $154 million in 2019, $47 million in 2020, and $170 million thereafter.

Further, the Company was a party to a five-year firm transportation commitment (the "Agreement") for a future crude oil pipeline project being considered for development that is not yet operational. The project requires the granting of regulatory approvals and requires additional construction efforts by the counterparty before being completed. The project has faced significant delays and has failed to gain the necessary permits and approvals. As a result of the persistent delays and lack of regulatory approval, the Agreement’s basic assumptions and purpose have become commercially impracticable. Accordingly, in 2015 the Company provided a shipper termination notice pursuant to the Agreement and formally provided the counterparty with the Company’s termination of the Agreement in its entirety. The Company's previously disclosed commitments under the Agreement totaled approximately $260 million, which are no longer expected to be incurred.

The Company’s pipeline commitments are for production primarily in the North region. The Company is not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Fuel purchase commitment – The Company has entered into a forward purchase contract with a third party to purchase specified quantities of diesel fuel at specified prices each month through June 2016 for use in drilling operations. Over the remaining contract term, the Company has committed to purchase approximately 11 million gallons of diesel fuel at varying prices depending on the grade of diesel fuel purchased and the timing and location of delivery. The contract satisfies a significant portion of the Company's anticipated diesel fuel needs and provides for physical delivery to desired locations. Future commitments under the arrangement as of December 31, 2015 total approximately $31

million, all of which will be incurred in 2016.
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 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 seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the proposed class. On November 3, 2014, plaintiffs filed an Amended Petition that did not add any substantive claims, but sought a “hybrid class action” in which they sought certification of certain claims for injunctive relief, reserving the right to seek a further class certification on money damages in the future. Plaintiffs filed an Amended Motion for Class Certification on January 9, 2015, that modified the proposed class to royalty owners in Oklahoma production from July 1, 1993, to the present (instead of 1980 to the present) and sought certification of over 45 separate “issues” for injunctive or declaratory relief, again, reserving the right to seek a further class certification of money damages in the future. The Company responded to the petition, its amendment, and the motions for class certification denying the allegations and raising a number of affirmative defenses and legal arguments to each of the claims and filings. Certain discovery was undertaken and the “hybrid” motion was briefed by plaintiffs and the Company. A hearing on the “hybrid” class certification was held on June 1st and 2nd, 2015. On June 11, 2015, the trial court certified a “hybrid” class as requested by plaintiffs. The Company has appealed the trial court’s class certification order, which will be reviewed de novo by the appellate court. The appeal briefing is complete and ready for determination by the court. An unsuccessful mediation was conducted on December 7, 2015. The Company is not currently able to estimate a reasonably possible loss or range of loss or what impact, if any, the action will 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 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. Although not currently at issue in the “hybrid” certification, plaintiffs have alleged underpayments in excess of $200 million that they may claim as damages, which may increase with the passage of time, a majority of which would be comprised of interest. The Company disputes plaintiffs’ claims, disputes that the case meets the requirements for a class action and is vigorously defending the case. The Company will continue to assert its defenses to the case as certified as well as any future attempt to certify a money damages class.
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, 2015 and 2014, the Company had recorded a liability on the consolidated balance sheets under the caption “Other noncurrent liabilities” of $6.1 million and $2.9 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 affiliate transactions reflected in the consolidated statements of comprehensive income (loss) include transactions between the Company and 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, which resulted in a reduction in certain affiliate transactions recognized in the Company's financial statements at December 31, 2015 and for the year then ended.
The Company historically sold a portion of its natural gas production to Hiland. For the years ended December 31, 2015, 2014, and 2013, these sales amounted to $1.4 million, $95.1 million, and $100.4 million, respectively, net of transportation and processing costs, and are included in the caption “Crude oil and natural gas sales to affiliates” in the consolidated statements of comprehensive income (loss). At December 31, 2015 nothing was due to the Company and at December 31, 2014, $13.1 million was due to the Company from Hiland, which is included in the caption “Receivables—Affiliated parties” in the consolidated balance sheets. At December 31, 2015 nothing was due from the

Company and at December 31, 2014, $0.3 million was due from the Company to Hiland for transportation and processing costs associated with the transactions, which is included in the caption “Payables to affiliated parties” in the consolidated balance sheets.

In prior years, the Company engaged in crude oil trades with an affiliate from time to time to obtain space on pipeline systems in the Company's operating areas. There were no crude oil purchases or sales with affiliates in 2015 or 2014. In 2013, the Company purchased 30,000 barrels from an affiliate for $3.0 million and had no crude oil sales to the affiliate.

The Company capitalized costs of $2.6 million, $5.9 million and $5.7 million in 2015, 2014, and 2013, respectively, associated with drilling rig services 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 were $1.7 million, $5.1 million and $1.4 million for the years ended December 31, 2015, 2014, and 2013, respectively. The total amount paid to these affiliates, a portion of which was billed to other interest owners, was $7.7 million, $58.2 million and $48.5 million for the years ended December 31, 2015, 2014, and 2013, respectively. At December 31, 2015 nothing was due to these affiliates and at December 31, 2014, $5.6 million was due to these affiliates related to the transactions, which is included in the caption “Payables to affiliated parties” in the consolidated balance sheets.

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 $0.7 million, $1.7 million, and $2.3 million and received payments from these affiliates of $0.5 million, $0.8 million, and $1.3 million during the years ended December 31, 2015, 2014, and 2013, respectively, relating to the operations of the respective properties. At December 31, 2015 and 2014, $106,000 and $207,000 was due from these affiliates and approximately $52,000 and $133,000 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 and crews 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. For usage during 2015, 2014, and 2013, the Company charged affiliates approximately $9,600, $51,000, and $55,000, respectively, for use of its corporate aircraft, crews, fuel, utilities and reimbursement of expenses and received $33,000, $39,000, and $379,000 from affiliates in 2015, 2014, and 2013, respectively. The Company was charged $236,000, $97,000, and $51,000, respectively, by affiliates for use of their aircraft and reimbursement of expenses during 2015, 2014, and 2013 and paid $221,000, $34,000, and $238,000 to the affiliates in 2015, 2014, and 2013, respectively.

The Company incurred costs for various field projects that have 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 and 2014 associated with the projects was $8.8 million and $1.8 million, respectively. The total amount paid, a portion of which was billed to other interest owners, was $9.2 million and $1.9 million for 2015 and 2014 respectively. Nothing was owed by the Company at December 31, 2015 and $1.2 million was owed by the Company at December 31, 2014, which is included in the caption “Payables to affiliated parties” in the consolidated balance sheets.

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Note 12. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2005 Long-Term Incentive Plan (“2005 Plan”) and 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 $51.8 million, $54.4 million, and $39.9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

In May 2013, the Company adopted the 2013 Plan and reserved a maximum of 19,680,072 shares of common stock that may be issued pursuant to the plan. The 2013 Plan replaced the Company's 2005 Plan as the instrument used to grant long-term incentive awards and no further awards will be granted under the 2005 Plan. However, restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms. As of December 31, 2015, the Company had a maximum of 17,028,213 shares of restricted stock available to grant to officers, directors and employees 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, 2005 Plan, or agreement relevant to a given award, includes the right to vote the restricted stock or 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, 2012 to December 31, 2015 is presented below.

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2012	3,258,924	$31.64
Granted	522,518	48.98
Vested	(929,618)	23.65
Forfeited	(137,512)	35.96
Non-vested restricted shares at December 31, 2013	2,714,312	$37.50
Granted	1,424,764	61.11
Vested	(1,007,166)	35.91
Forfeited	(453,146)	44.90
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

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 a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company’s restricted stock. The fair value at the vesting date of restricted stock that vested during 2015, 2014 and 2013 was $23.6 million, $58.2 million and $49.4 million, respectively. As of December 31, 2015, there was approximately $67 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized ratably over a weighted average period of 1.2 years.

Note 13. Accumulated Other Comprehensive Loss

Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in "Accumulated other comprehensive loss" within shareholders' equity on the consolidated balance sheets. The following table summarizes the change in accumulated other comprehensive loss for the years ended December 31, 2015 and 2014:

	Year ended December 31,	
In thousands	2015	2014
Beginning accumulated other comprehensive loss, net of tax	$(385)	$—
Foreign currency translation adjustments	(2,969)	(385)
Income tax benefit (1)	—	—
Other comprehensive loss, net of tax	(2,969)	(385)
Ending accumulated other comprehensive loss, net of tax	$(3,354)	$(385)

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

Note 14. Property Dispositions

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

During the year ended December 31, 2014, the Company sold certain non-strategic properties in various areas to third parties for proceeds totaling $129.4 million. The proceeds primarily related to dispositions of properties in the Niobrara play in Colorado and Wyoming in March 2014 for proceeds totaling $30.3 million and $85.8 million of proceeds received in conjunction with the disposition of a portion of the Company's Northwest Cana properties in Oklahoma in September 2014. The disposed properties represented an immaterial portion of the Company's total proved reserves, production, and revenues.

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, 2015, 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, 2015, 2014 and 2013.

	Year ended December 31,		
In thousands	2015	2014	2013
Crude oil and natural gas sales	$2,552,531	$4,203,022	$3,573,431
Production expenses	(348,897)	(352,472)	(282,197)
Production taxes and other expenses	(200,637)	(349,760)	(298,787)
Exploration expenses	(19,413)	(50,067)	(34,947)
Depreciation, depletion, amortization and accretion	(1,722,336)	(1,338,351)	(953,796)
Property impairments	(402,131)	(616,888)	(220,508)
Income tax benefit (provision)	33,680	(559,311)	(659,783)
Results from crude oil and natural gas producing activities	$(107,203)	$936,173	$1,123,413

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, 2015, 2014 and 2013 are presented below:

	Year ended December 31,		
In thousands	2015	2014	2013
Property acquisition costs:			
Proved	$557	$48,917	$16,604
Unproved	168,492	409,529	546,881
Total property acquisition costs	169,049	458,446	563,485
Exploration Costs	241,523	863,606	687,767
Development Costs	2,148,530	3,670,448	2,549,203
Total	$2,559,102	$4,992,500	$3,800,455

Exploration costs above include asset retirement costs of $3.3 million, $1.2 million and $1.8 million and development costs above include asset retirement costs of $19.5 million, $19.1 million and $6.0 million for the years ended December 31, 2015, 2014 and 2013, 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, 2015 and 2014 are as follows:

	December 31,	
In thousands	2015	2014
Proved crude oil and natural gas properties	$19,520,724	$17,045,967
Unproved crude oil and natural gas properties	682,988	966,080
Total	20,203,712	18,012,047
Less accumulated depreciation, depletion and amortization	(6,374,218)	(4,601,864)
Net capitalized costs	$13,829,494	$13,410,183

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	2015	2014	2013
Balance at January 1	$93,421	$152,775	$92,699
Additions to capitalized exploratory well costs pending determination of proved reserves	132,806	627,853	548,933
Reclassification to proved crude oil and natural gas properties based on the determination of proved reserves	(160,779)	(671,618)	(479,507)
Capitalized exploratory well costs charged to expense	(6,051)	(15,589)	(9,350)
Balance at December 31	$59,397	$93,421	$152,775
Number of gross wells	73	119	67

As of December 31, 2015, exploratory drilling costs of $1.7 million, representing three non-operated wells, were suspended one year beyond the completion of drilling. Evaluation of these non-operated wells is not within the Company's control and a final determination by the operator may not occur until 2017. Of the suspended costs, $0.1 million was incurred in 2014 and $1.6 million was incurred in 2013.

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. ("Ryder Scott") prepared reserve estimates for properties comprising approximately 99%, 99%, and 99% of the Company’s discounted future net cash flows (PV-10) as of December 31, 2015, 2014, and 2013, respectively. Properties comprising 99% of proved crude oil reserves and 97% of proved natural gas reserves were evaluated by Ryder Scott as of December 31, 2015. 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 recorded for the Company's Canadian operations at December 31, 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 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, 2015, 2014 and 2013 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, 2015, 2014 and 2013 were not material and have not been included in the reserve estimates.

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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, 2012	561,163	1,341,084	784,677
Revisions of previous estimates	(55,783)	(241,623)	(96,054)
Extensions, discoveries and other additions	267,009	1,065,870	444,654
Production	(34,989)	(87,730)	(49,610)
Sales of minerals in place	—	—	—
Purchases of minerals in place	388	419	458
Proved reserves as of December 31, 2013	737,788	2,078,020	1,084,125
Revisions of previous estimates	(67,151)	(244,783)	(107,949)
Extensions, discoveries and other additions	239,526	1,206,569	440,621
Production	(44,530)	(114,295)	(63,579)
Sales of minerals in place	(123)	(18,623)	(3,227)
Purchases of minerals in place	850	1,498	1,100
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. 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, operating costs or development costs.

Downward revisions to proved reserves in 2013 primarily represented the removal of PUD reserves resulting from a decision in 2013 to focus the Company's drilling program on certain areas of the Bakken and SCOOP plays with more attractive rates of return and multi-well pad drilling capabilities, while building on success in the Company's development of the Lower Three Forks reservoirs in the Bakken.

Downward revisions to proved reserves in 2014 resulted from the Company refining its drilling program and reducing its planned rig count in response to the significant decrease in crude oil prices in the latter part of 2014, which contributed to the removal of PUD reserves no longer scheduled to be developed within five years from the date in which they were first booked.

Downward revisions to proved reserves in 2015 resulted primarily from the significant decrease in commodity prices in 2015. The 12-month average price for crude oil decreased 47% from $94.99 per Bbl for 2014 to $50.28 per Bbl for 2015, while the 12-month average price for natural gas decreased 41% from $4.35 per MMBtu for 2014 to $2.58 per MMBtu for 2015. These decreases shortened the economic lives of certain producing properties and caused certain exploration and development projects to become uneconomic which had an adverse impact on the Company's proved reserve estimates, resulting in downward revisions of 185 MMBo and 391 Bcf (totaling 251 MMBoe) in 2015.

In response to the continued decrease in commodity prices throughout 2015, the Company has further refined its drilling program and reduced its planned rig count to concentrate its efforts in core areas of North Dakota and Oklahoma that provide the best opportunities to improve recoveries and rates of return. The refinement of the Company's drilling program contributed to the removal of PUD reserves no longer scheduled to be developed within five years from the date in which they were first booked. One element leading to the removal is an increased emphasis on multi-well pad drilling in the Bakken, which resulted in the removal of PUDs in certain areas in favor of PUDs more likely to be developed with pad drilling where operating efficiencies may be realized. Further, in the SCOOP play the Company removed certain PUD locations originally planned to be developed with standard lateral drilling lengths in favor of PUDs to be developed with extended length laterals in similar locations that provide opportunities for improved well productivity and economics. The combination of these and other factors resulted in the removal of 65 MMBo and 197 Bcf (totaling 98 MMBoe) of PUD reserves in 2015. Additionally, changes in anticipated production performance on certain properties resulted in 63 MMBo of downward revisions to crude oil proved reserves and 125 Bcf of upward revisions to natural gas proved reserves (netting to 42 MMBoe of downward revisions) in 2015.

The downward revisions described above were partially offset by upward revisions in 2015 due to lower operating costs being realized in conjunction with depressed commodity prices and improvements in operating efficiencies as well as other factors.

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 activity in our Bakken and SCOOP plays. Proved reserve additions in the Bakken totaled 75 MMBo and 124 Bcf (totaling 96 MMBoe) and reserve additions in SCOOP totaled 36 MMBo and 340 Bcf (totaling 93 MMBoe) for the year ended December 31, 2015. Additionally, 2015 extensions and discoveries were significantly impacted by successful drilling results in the Northwest Cana/STACK area, resulting in proved reserve additions of 20 MMBo and 222 Bcf (totaling 57 MMBoe) in 2015.

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 notable 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, 2015, 2014 and 2013:

	December 31,		
	2015	2014	2013
Proved Developed Reserves			
Crude oil (MBbl)	326,798	342,137	278,630
Natural Gas (MMcf)	1,190,343	962,051	768,969
Total (MBoe)	525,188	502,479	406,792
Proved Undeveloped Reserves			
Crude oil (MBbl)	373,716	524,223	459,158
Natural Gas (MMcf)	1,961,443	1,946,335	1,309,051
Total (MBoe)	700,623	848,612	677,333
Total Proved Reserves			
Crude oil (MBbl)	700,514	866,360	737,788
Natural Gas (MMcf)	3,151,786	2,908,386	2,078,020
Total (MBoe)	1,225,811	1,351,091	1,084,125

Proved developed reserves are reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves 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.

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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, 2015, 2014 and 2013.

	December 31,		
In thousands	2015	2014	2013
Future cash inflows	$36,551,672	$90,867,459	$78,646,274
Future production costs	(10,869,493)	(25,799,221)	(21,333,460)
Future development and abandonment costs	(6,935,958)	(12,842,174)	(10,250,789)
Future income taxes	(3,717,612)	(13,800,737)	(12,447,127)
Future net cash flows	15,028,609	38,425,327	34,614,898
10% annual discount for estimated timing of cash flows	(8,552,325)	(19,992,293)	(18,319,131)
Standardized measure of discounted future net cash flows	$6,476,284	$18,433,034	$16,295,767

The weighted average crude oil price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $41.63, $84.54, and $91.50 per barrel at December 31, 2015, 2014 and 2013, respectively. The weighted average natural gas price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $2.35, $6.06, and $5.36 per Mcf at December 31, 2015, 2014 and 2013, 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	2015	2014	2013
Standardized measure of discounted future net cash flows at January 1	$18,433,034	$16,295,767	$11,180,357
Extensions, discoveries and improved recoveries, less related costs	1,091,283	5,516,528	6,613,665
Revisions of previous quantity estimates	(2,156,028)	(1,755,366)	(1,765,300)
Changes in estimated future development and abandonment costs	5,008,731	476,665	1,942,585
Purchases (sales) of minerals in place, net	(7,768)	(3,196)	12,012
Net change in prices and production costs	(16,111,142)	(1,925,349)	263,541
Accretion of discount	1,843,303	1,629,576	1,118,036
Sales of crude oil and natural gas produced, net of production costs	(2,002,997)	(3,500,790)	(2,992,447)
Development costs incurred during the period	1,394,584	2,466,748	1,210,223
Change in timing of estimated future production and other	(3,844,259)	(309,902)	464,111
Change in income taxes	2,827,543	(457,647)	(1,751,016)
Net change	(11,956,750)	2,137,267	5,115,410

Standardized measure of discounted future net cash flows at December 31	$6,476,284	$18,433,034	$16,295,767

Note 17. Quarterly Financial Data (Unaudited)

The Company’s unaudited quarterly financial data for 2015 and 2014 is summarized below.

	Quarter ended			
In thousands, except per share data	March 31	June 30	September 30	December 31
2015				
Total revenues (1)	$625,644	$796,374	$ 682,669	$ 575,480
Gain (loss) on derivative instruments, net (1)	$32,755	$(4,737)	$ 46,527	$ 16,540
Property impairments (2)	$147,561	$76,872	$ 96,697	$ 81,001
Income (loss) from operations	$(111,276)	$82,447	$ (52,356)	$ (142,816)
Net income (loss)	$(131,971)	$403	$ (82,423)	$ (139,677)
Net income (loss) per share:				
Basic	$(0.36)	$—	$ (0.22)	$ (0.38)
Diluted	$(0.36)	$—	$ (0.22)	$ (0.38)
2014			(3)	(4)
Total revenues (1)	$972,495	$886,095	$ 1,645,328	$ 1,297,700
Gain (loss) on derivative instruments, net (1)	$(39,674)	$(262,524)	$ 473,999	$ 387,958
Property impairments (2)	$58,208	$79,316	$ 85,561	$ 393,803
Income from operations	$421,317	$236,394	$ 944,897	$ 265,228
Net income	$226,234	$103,538	$ 533,521	$ 114,048
Net income per share:				
Basic	$0.61	$0.28	$ 1.45	$ 0.31
Diluted	$0.61	$0.28	$ 1.44	$ 0.31

(1) Gains and losses on mark-to-market derivative instruments are reflected in “Total revenues” on both the consolidated statements of comprehensive income (loss) and this table of unaudited quarterly financial data. 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 fluctuations in income (loss) that are 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) The 2014 third quarter includes a $24.5 million pre-tax ($15.4 million after tax, or $0.04 per basic and diluted share) loss on extinguishment of debt as discussed in Note 7. Long-Term Debt.

(4) Balances for the fourth quarter of 2014 include $433 million of pre-tax gains ($273 million after tax, or $0.74 per basic and diluted share) recognized from crude oil derivative contracts that were settled prior to their contractual maturities.

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 that the Company's disclosure controls and procedures were effective as of December 31, 2015 to ensure that 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 that 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 2015 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 2015 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, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 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 24, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

We have audited the internal control over financial reporting of Continental Resources, Inc. (an Oklahoma corporation) and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in 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), the consolidated financial statements of the Company as of and for the year ended December 31, 2015, and our report dated February 24, 2016 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 24, 2016

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 2016 (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 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.

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. filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-32886) filed November 6, 2012 and incorporated herein by reference.
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 February 24, 2012 as Exhibit 4.1 to the Company’s 2011 Form 10-K (Commission File No. 001-32886) 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 April 5, 2010 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust FSB, as trustee.
4.4***	Indenture dated as of September 16, 2010 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust FSB, as trustee.
4.5	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 4.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-32886) filed March 8, 2012 and incorporated herein by reference.
4.6	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.
4.7	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.
4.8	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 filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed August 17, 2012 and incorporated herein by reference.
10.1†	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006 filed as Exhibit 10.9 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.

10.2†	Form of Restricted Stock Award Agreement under the Continental Resources, Inc. 2005 Long-Term Incentive Plan filed as Exhibit 10.10 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†	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.
10.4†	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.
10.5†	First Amendment to the Continental Resources, Inc. 2005 Long-Term Incentive Plan filed February 28, 2013 as Exhibit 10.2 to the Company’s 2012 Form 10-K (Commission File No. 001-32886) and incorporated herein by reference.
10.6†	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.
10.7†	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.
10.8†	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.
10.9†	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.
10.10†	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.
10.11	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.
10.12†	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.
10.13†	Description of cash bonus plan approved as of March 20, 2015 filed as Exhibit 10.1 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.
10.14	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.
10.15†	Summary of Non-Employee Director Compensation Approved as of May 19, 2015 to be effective July 1, 2015 filed as Exhibit 10.2 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.
10.16	Term Loan Agreement dated as of November 4, 2015 among Continental Resources, Inc., as borrower, and its subsidiaries Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, as guarantors, and MUFG Union Bank, N.A., as Administrative Agent, Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A. and Mizuho Bank, LTD., as Co-Syndication Agents, and Compass Bank, Toronto Dominion (Texas) LLC and U.S. Bank National Association, as Co-Documentation Agents, and the other lenders party thereto filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended September 30, 2015 (Commission File No. 001-32886) filed November 4, 2015 and incorporated herein by reference.

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)
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 24, 2016

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 Harold G. Hamm	Chairman of the Board and Chief Executive Officer (principal executive officer)	February 24, 2016
/s/ JOHN D. HART John D. Hart	Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 24, 2016
/s/ DAVID L. BOREN David L. Boren	Director	February 24, 2016
/s/ WILLIAM B. BERRY William B. Berry	Director	February 24, 2016
/s/ LON MCCAIN Lon McCain	Director	February 24, 2016
/s/ JOHN T. MCNABB II John T. McNabb II	Director	February 24, 2016
/s/ MARK E. MONROE Mark E. Monroe	Director	February 24, 2016