CONTINENTAL RESOURCES, INC
Form 10-K
February 24, 2015

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, 2014

or

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

For the transition period from to

Commission File Number: 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. x

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

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨ (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, 2014 was approximately $9.1 billion, based upon the closing price of $158.04 per share ($79.02 per share adjusted for September 2014 stock split) as reported by the New York Stock Exchange on such date.

371,906,845 shares of our $0.01 par value common stock were outstanding on February 17, 2015.

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 2015, 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 a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir.

"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 south central Oklahoma.
"spacing" The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.
"standardized measure" Discounted future net cash flows estimated by applying the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January to December to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax 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, statements or information concerning the Company’s future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, returns, budgets, costs, business strategy, objectives, and cash flow, included in this report are forward-looking statements. The words “could,” “may,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “bud “continue,” “potential,” “guidance,” “strategy” and 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 business and financial strategy;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- our 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;
- 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 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 considers these expectations to be reasonable and based on reasonable assumptions, 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 our control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. 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.

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, our 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 otherwise required by applicable law, we do not intend, and disclaim any duty, to 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 exploration and production 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 Kansas and all properties south of Kansas and west of the Mississippi River including various plays in the South Central Oklahoma Oil Province (“SCOOP”), Northwest Cana, and Arkoma 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 we are now geographically concentrated, with that region comprising approximately 74% of our crude oil and natural gas production and approximately 83% of our crude oil and natural gas revenues for the year ended December 31, 2014. Approximately 69% of our estimated proved reserves as of December 31, 2014 are located in the North region. In 2012 and 2013, we significantly expanded our activity in our South region with our discovery and announcement of the SCOOP play in Oklahoma. Our South region now comprises 26% of our crude oil and natural gas production and 31% of our estimated proved reserves as of December 31, 2014.

We have focused our operations on the exploration and development of crude oil since the 1980s. For the year ended December 31, 2014, crude oil accounted for approximately 70% of our total production and approximately 85% of our crude oil and natural gas revenues. Crude oil represents approximately 64% of our estimated proved reserves as of December 31, 2014.

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 economically 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, 2014, our estimated proved reserves were 1,351 MMBoe, with estimated proved developed reserves of 502 MMBoe, or 37% of our total estimated proved reserves. For the year ended December 31, 2014, we generated crude oil and natural gas revenues of $4.2 billion and operating cash flows of $3.4 billion. For the year ended December 31, 2014, production averaged 174,189 Boe per day, a 28% increase over average production of 135,919 Boe per day for the year ended December 31, 2013. Average daily production for the quarter ended December 31, 2014 increased 34% to 193,456 Boe per day from 144,254 Boe per day for the quarter ended December 31, 2013.

On August 18, 2014, our Board of Directors declared a 2-for-1 stock split of our common stock to be effected in the form of a stock dividend. The stock dividend was distributed on September 10, 2014 to shareholders of record as of September 3, 2014. All previously reported common stock and earnings per share amounts have been retroactively adjusted throughout this Form 10-K to reflect the stock split.

The table below summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2014, average daily production for the quarter ended December 31, 2014 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.

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	December 31, 2014						
	Proved reserves (MBoe)	Percent of total	PV-10 (1) (In millions)	Net producing wells	Average daily production for fourth quarter 2014 (Boe per day)	Percent of total	Annualized reserve/production index (2)
North Region:							
Bakken field							
North Dakota Bakken	802,787	59.4 %	$ 13,918	1,049	115,137	59.5 %	19.1
Montana Bakken	62,817	4.6 %	1,273	274	15,646	8.1 %	11.0
Red River units							
Cedar Hills	49,769	3.7 %	1,295	131	9,883	5.1 %	13.8
Other Red River units	15,133	1.1 %	250	123	3,376	1.7 %	12.3
Other	4,523	0.3 %	84	5	690	0.4 %	18.0
South Region:							
SCOOP	369,742	27.4 %	5,493	146	40,403	20.9 %	25.1
Northwest Cana	26,718	2.0 %	253	64	3,780	2.0 %	19.4
Arkoma Woodford	10,257	0.8 %	85	58	2,318	1.2 %	12.1
Other	9,345	0.7 %	119	250	2,223	1.1 %	11.5
Total	1,351,091	100.0 %	$ 22,770	2,100	193,456	100.0 %	19.1

(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 $4.3 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 2014 production into estimated proved reserve volumes at December 31, 2014.

Our Business Strategy

Our business strategy is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of this strategy are:

Focus on crude oil. During the 1980s we began to believe the long-term valuation potential for crude oil exceeded that of natural gas. Accordingly, we began to shift our reserve and production profiles toward crude oil. As of December 31, 2014, crude oil comprised 64% of our total proved reserves, 70% of our 2014 annual production, and 85% of our 2014 crude oil and natural gas revenues.

Growth Through Drilling. A substantial portion of our annual capital expenditures are invested in drilling projects and acreage acquisitions. From January 1, 2010 through December 31, 2014, proved crude oil and natural gas reserve additions through extensions and discoveries were 1,376 MMBoe compared to 86 MMBoe of proved reserve acquisitions during that same period.

Internally Generated Prospects. Although we periodically evaluate and complete strategic acquisitions, our technical staff has internally generated a substantial portion of the opportunities for the investment of our capital. As an early entrant in new or emerging plays, we expect to acquire undeveloped acreage at a lower cost than later entrants into a developing play.

Focus on Unconventional Crude Oil and Natural Gas Resource Plays. Our experience with three dimensional seismic, horizontal drilling, geosteering technologies, advanced completion technologies (e.g., fracture stimulation) and enhanced recovery technologies allows us to economically develop unconventional crude oil and natural gas resource reservoirs, such as the Red River B Dolomite and Bakken formations in our North region and various formations in Oklahoma. Our production from the Bakken, Red River units, SCOOP, Northwest Cana and Arkoma Woodford areas comprised approximately 62,436 MBoe, or 98%, of our total crude oil and natural gas production for the year ended December 31, 2014.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 900,808 net undeveloped acres held in the Bakken, Red River units, SCOOP, Northwest Cana and Arkoma Woodford areas, we held 651,240 net undeveloped acres in other crude oil and natural gas plays as of December 31, 2014. Our technical staff is focused on identifying and testing new unconventional crude oil and natural gas resource plays where significant reserves could be developed if economically producible volumes can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

Our Business Strengths

We have a number of strengths we believe will help us successfully execute our business strategy, including the following:

Large Acreage Inventory. We held approximately 1.6 million net undeveloped acres and 1.1 million net developed acres as of December 31, 2014. Approximately 58% of the net undeveloped acres are located within unconventional resource plays in the Bakken, SCOOP, Northwest Cana and Arkoma Woodford areas. As of December 31, 2014, we controlled the largest leasehold positions in the Bakken and SCOOP with approximately 1.2 million net acres and 480,200 net acres under lease in those respective plays. Being an early entrant in Bakken and SCOOP has allowed us to capture significant acreage positions in core parts of the plays.

Experience with Horizontal Drilling and Enhanced Recovery Methods. We have substantial experience with horizontal drilling and enhanced recovery methods and continue to be among industry leaders in the use of new drilling and completion technologies. Our trademarked ECO-Pad drilling concept, which allows for drilling multiple wells from a single pad, is a standard drilling approach in the industry because it improves land use and increases operating efficiencies. We have drilled as many as 14 wells on a pad site and have the opportunity to increase this number in the future based on surface availability, technology and well spacing. We are also among industry leaders in extending lateral drilling lengths, in some instances up to three miles. Longer laterals are believed to have a positive impact on well productivity and economics. Additionally, we have extensive expertise in the exploration and development of the lower layers or “benches” of the Three Forks formation in the Bakken field, initially targeting the first bench of the Three Forks in mid-2008 followed by completion of wells in the second, third, and fourth benches in 2011, 2012, and 2013, respectively. In 2013 and 2014 we performed pilot density tests designed to determine optimum well spacing and pattern for full field development of the Bakken and Three Forks formations, the results of which are being used to guide future development plans. We have also been among industry leaders in testing enhanced completion technologies involving various combinations of fluid types, proppant volumes and stimulation stage lengths to determine optimal methods for maximizing crude oil recoveries and returns.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2014, we operated properties comprising 83% of our total proved reserves and 81% of our PV-10. By controlling 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 crude oil and natural gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the crude oil and natural gas industry in 1967. Our 9 senior officers have an average of 31 years of crude oil and natural gas industry experience.

Strong Financial Position. Our corporate credit rating is currently rated as investment grade by Moody’s Investor Services, Inc. and Standard & Poor’s Ratings Services. We have experienced significant growth with our success in the development of the Bakken field and more recently the SCOOP play. Our growth has been matched with a capital sourcing approach which has enabled a strong credit profile. As of February 17, 2015, we have a credit facility with lender commitments totaling $2.5 billion which may be increased up to a total of $4.0 billion to provide additional liquidity if needed to maintain our growth strategy, take advantage of business opportunities, and fund our capital program and commitments. We had $1.9 billion of available borrowing capacity under our credit facility at February 17, 2015 after considering outstanding borrowings and letters of credit. We have no near-term senior note maturities, with our earliest maturity being $200 million due in October 2020. We believe our planned exploration and development activities will be funded substantially from our operating cash flows and credit facility borrowings. Our 2015 capital expenditures budget is reflective of the significant decrease in commodity prices in recent months and has been established based on an expectation of available cash flows from operations and availability under our credit facility. If operating 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 on our credit facility if needed to fund our operations.

3

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, 2014. The total Standardized Measure of discounted cash flows as of December 31, 2014 is also presented. Our reserve estimates as of December 31, 2014 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 95% of our proved natural gas reserves as of December 31, 2014. 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, 2014 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2014 through December 2014, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were $94.99 per Bbl for crude oil and $4.35 per MMBtu for natural gas ($84.54 per Bbl for crude oil and $6.06 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	333,040	939,366	489,601	$12,181.3
Proved developed non-producing	9,097	22,685	12,878	342.8
Proved undeveloped	524,223	1,946,335	848,612	10,246.2
Total proved reserves	866,360	2,908,386	1,351,091	$22,770.3
Standardized Measure (1)				$18,433.0

(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 $4.3 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 proved crude oil and natural gas reserves by region as of December 31, 2014.

	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	220,704	350,375	279,100	433,858	538,971	523,687
Montana Bakken	32,928	31,520	38,181	20,321	25,889	24,636
Red River units						
Cedar Hills	48,264	6,495	49,347	422	—	422
Other Red River units	13,310	10,938	15,133	—	—	—
Other	288	19,204	3,489	96	5,629	1,034
South Region:						
SCOOP	24,016	366,053	85,025	69,027	1,294,144	284,717
Northwest Cana	1,036	69,396	12,602	499	81,702	14,116
Arkoma Woodford	11	61,475	10,257	—	—	—
Other	1,580	46,595	9,345	—	—	—
Total	342,137	962,051	502,479	524,223	1,946,335	848,612

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

	Year Ended December 31,		
MBoe	2014	2013	2012
Proved reserves at beginning of year	1,084,125	784,677	508,438
Revisions of previous estimates	(107,949)	(96,054)	4,149
Extensions, discoveries and other additions	440,621	444,654	233,652
Production	(63,579)	(49,610)	(35,716)
Sales of minerals in place	(3,227)	—	(7,838)
Purchases of minerals in place	1,100	458	81,992
Proved reserves at end of year	1,351,091	1,084,125	784,677

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.

In response to the significant decrease in crude oil prices in the latter part of 2014, which has continued into early 2015, we have refined our drilling program and lowered our planned rig count to concentrate our efforts in core areas of the Bakken and SCOOP that provide the opportunity 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 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 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 105 MMBoe of PUD reserves in 2014. These removals were made in accordance with SEC reserve rules and do not necessarily represent the elimination of recoverable hydrocarbons physically in place. In some instances the removed reserves may potentially be developed in the future given the right economic conditions. Commodity price revisions, based on 12-month average SEC prices for 2014, did not have a significant impact on our 2014 reserve revisions, but could potentially have a significant impact on 2015 reserve estimates if the currently depressed pricing environment for crude oil and natural gas persists or worsens.

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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. Proved reserve additions from our drilling activities in the Bakken totaled 222 MMBoe, 276 MMBoe and 185 MMBoe for the years ended December 31, 2014, 2013 and 2012, respectively. Additionally, extensions and discoveries were significantly impacted by successful drilling results in the SCOOP play in 2013 and more so in 2014, resulting in 158 MMBoe and 208 MMBoe of proved reserve additions for 2013 and 2014, respectively. Significant progress continued to be made in 2014 in developing and expanding our Bakken and SCOOP assets, both laterally and vertically, through strategic exploration, development, planning and technology. See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2014 drilling activities in the Bakken and SCOOP plays, among others. We expect a significant portion of future reserve additions will come from our major development projects in the Bakken and SCOOP.

Sales of minerals in place. These are reductions to proved reserves that result from the disposition of properties during a period. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 13. Property Acquisitions and 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 competitive terms.

Purchases of minerals in place. These are additions to proved reserves that result from the acquisition of properties during a period. Purchases for 2012 primarily reflect the Company's acquisitions of properties in the Bakken play of North Dakota. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 13. Property Acquisitions and Dispositions for further discussion of our 2012 acquisitions. We may continue to participate as a buyer of properties when and if we have the ability to increase our position in strategic plays at competitive terms.

Proved Undeveloped Reserves

Our PUD reserves at December 31, 2014 totaled 848,612 MBoe, consisting of 524,223 MBbls of crude oil and 1,946,335 MMcf of natural gas. Substantially all of our PUD reserves at December 31, 2014 are located in the Bakken and SCOOP plays, our most active development areas, with those plays comprising 65% and 34%, respectively, of our total PUD reserves at year-end 2014. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2014.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves at December 31, 2013	459,158	1,309,051	677,333
Revisions of previous estimates	(66,273)	(266,466)	(110,684)
Extensions and discoveries	204,970	1,097,708	387,921
Sales of minerals in place	(1)	(931)	(156)
Purchases of minerals in place	243	313	295
Conversion to proved developed reserves	(73,874)	(193,340)	(106,097)
Proved undeveloped reserves at December 31, 2014	524,223	1,946,335	848,612

Revisions of previous estimates. During the year ended December 31, 2014, we removed 306 gross (174 net) PUD locations, which resulted in the removal of 53 MMBo and 315 Bcf (105 MMBoe) of PUD reserves. These removals were due to the decrease in crude oil prices in late 2014 and resulting refinement of our drilling program to place greater emphasis on core areas of the Bakken and SCOOP that provide the opportunity 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 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.

Extensions and discoveries. Extensions and discoveries were primarily due to increases in PUD reserves associated with our successful drilling activity in the Bakken and SCOOP. PUD reserve additions in the Bakken totaled 157 MMBo and 196 Bcf (189 MMBoe) in 2014, while SCOOP PUD reserve additions totaled 48 MMBo and 873 Bcf

(193 MMBoe). See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2014 drilling activities in the Bakken and SCOOP plays.

Conversion to proved developed reserves. In 2014, we developed approximately 21% of our PUD locations and 16% of our PUD reserves booked as of December 31, 2013 through the drilling of 493 gross (264 net) development wells at an aggregate capital cost of approximately $2.0 billion.

Development plans. We have acquired substantial leasehold positions in the Bakken field and SCOOP play. Our drilling programs to date in those areas have focused on proving our undeveloped leasehold acreage through strategic exploratory drilling, thereby increasing the amount of leasehold acreage in the secondary term of the lease with no further drilling obligations (i.e., categorized as held by production) and resulting in a reduced amount of leasehold acreage in the primary term of the lease. While we will continue to drill strategic exploratory wells and build on our current leasehold position, we expect to continue increasing our focus on developing our PUD locations. Estimated future development costs relating to the development of PUD reserves are projected to be approximately $2.0 billion in 2015, $2.2 billion in 2016, $2.8 billion in 2017, $2.8 billion in 2018, and $2.4 billion in 2019. These capital projections are reflective of the significant decrease in commodity prices in recent months and have been established based on an expectation of available cash flows from operations and availability under our credit facility.

Development of our existing PUD reserves at December 31, 2014 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 crude oil prices or for other reasons have been removed from our reserves at December 31, 2014. We had no PUD reserves at December 31, 2014 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 95% of our proved natural gas reserves as of December 31, 2014 included in this Annual Report on 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. A copy of the Ryder Scott reserve report 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 Engineering 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 30 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 Engineering reports directly to our Senior Vice President—Operations and Resource Development. The reserve estimates are reviewed and approved by the President and Chief Operating Officer and certain other members of senior management.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acres by region as of December 31, 2014:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	999,847	576,265	466,243	298,606	1,466,090	874,871
Montana Bakken	185,579	148,486	215,365	142,496	400,944	290,982
Red River units	156,624	136,302	—	—	156,624	136,302
Other	19,238	6,321	378,959	279,111	398,197	285,432
South Region:						
SCOOP	125,575	87,478	681,208	392,685	806,783	480,163
Northwest Cana	120,809	73,217	112,022	66,760	232,831	139,977
Arkoma Woodford	110,580	26,269	3,594	261	114,174	26,530
Other	104,253	49,875	240,477	184,320	344,730	234,195
East Region	—	—	196,109	187,809	196,109	187,809
Total	1,822,505	1,104,213	2,293,977	1,552,048	4,116,482	2,656,261

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2014 that are 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.

	2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	146,902	89,593	153,746	96,622	72,789	53,705
Montana Bakken	71,318	43,731	60,276	44,225	48,534	33,417
Red River units	5,714	4,911	17,230	11,394	4,159	3,173
Other	65,902	37,391	12,043	5,953	639	256
South Region:						
SCOOP	140,180	88,276	217,200	119,204	147,451	97,420
Northwest Cana	29,698	15,219	40,575	29,701	27,876	15,557
Arkoma Woodford	—	—	—	—	—	—
Other	159,266	121,600	23,421	34,195	41,108	19,657
East Region	14,187	9,760	4,612	4,318	48,547	48,412
Total	633,167	410,481	529,103	345,612	391,103	271,597

Drilling Activity

During the three years ended December 31, 2014, we drilled exploratory and development wells as set forth in the table below:

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	94	70.5	75	51.5	76	37.0
Natural gas	42	8.3	40	23.7	78	43.8
Dry holes	3	1.6	3	2.1	1	1.0
Total exploratory wells	139	80.4	118	77.3	155	81.8
Development wells:						
Crude oil	897	290.3	734	250.9	561	211.3
Natural gas	64	16.8	26	5.4	5	2.4
Dry holes	1	1.0	—	—	3	1.1
Total development wells	962	308.1	760	256.3	569	214.8
Total wells	1,101	388.5	878	333.6	724	296.6

As of December 31, 2014, there were 575 gross (213.2 net) operated and non-operated wells in the process of drilling, completing or waiting on completion.

As of February 17, 2015, we operated 36 rigs on our properties. To align our capital expenditures with lower commodity prices, we plan to decrease our average operated rig count to approximately 34 by the end of first quarter 2015 and average approximately 31 operated rigs for full-year 2015. Our rig activity during 2015 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. There can be no assurance, however, that rigs will be available to us at an attractive cost. 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 currently budgeted number of wells and capital expenditures for 2015 in our key operating areas. Our 2015 capital expenditures budget is reflective of the significant decrease in commodity prices in recent months and has been established based on an expectation of available cash flows from operations and availability under our credit facility. If operating 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 on our credit facility if needed to fund our operations. Conversely, higher operating cash flows resulting from an increase in commodity prices could result in increased capital expenditures.

The following table provides information regarding well counts and the budgeted capital we plan to spend on drilling, capital workovers, and facilities in 2015 by operating area.

	2015 Plan		
	Gross wells planned for drilling	Net wells planned for drilling	Capital expenditures (1) (in millions)
North Region:			
Bakken field			
North Dakota Bakken	623	186	$1,577
Montana Bakken	8	5	23
Red River units	2	2	44
Other	7	4	56
South Region:			
SCOOP	157	81	741
Northwest Cana	16	5	40

Other	—	—	2
Total	813	283	$2,483

(1) The capital expenditures reflected above include amounts for drilling, capital workovers and facilities and exclude budgeted amounts of $180 million for land, $12 million for seismic, and $25 million for vehicles, computers and other equipment. Potential acquisition expenditures are not budgeted.

North Region

Our properties in the North region represented 74% of our PV-10 as of December 31, 2014 and 75% of our average daily Boe production for the fourth quarter of 2014. Our average daily production from such properties was 144,732 Boe per day for the fourth quarter of 2014, an increase of 33% over the comparable 2013 period. Our principal producing properties in the North region are 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. In April 2013, the U.S. Geological Survey released an updated estimate of reserves located in the Bakken field. The assessment projects that the Bakken field contains an estimated mean of 7.4 billion barrels, with a potential of up to 11.4 billion barrels, of undiscovered, technically recoverable crude oil using current technology. In April 2014, the Bakken field reached a milestone with the production of its 1 billionth barrel of crude oil from the formation, with the majority of this production coming in the last three years. According to data published by the U.S. Energy Information Administration for November 2014, North Dakota is the second largest oil producing state in the U.S. due to production growth in the Bakken field.

In 2014, we continued to be a leading producer, leasehold owner and driller in the Bakken field. Our Bakken production averaged 130,783 Boe per day during the fourth quarter of 2014, up 40% from the 2013 fourth quarter. As of December 31, 2014, we controlled the largest leasehold position in the Bakken field with approximately 1.9 million gross (1.2 million net) acres. We are one of the most active drillers in the Bakken, with 21 active operated rigs as of December 31, 2014. Our total proved Bakken field reserves as of December 31, 2014 were 866 MMBoe, an increase of 17% compared to December 31, 2013.

We continued to make significant progress with our development and exploratory drilling programs in the Bakken field during 2014 as summarized in the following North Dakota and Montana discussions.

North Dakota Bakken

Our production and reserve growth in the Bakken field during 2014 came primarily from our activities in North Dakota. Production in North Dakota increased to an average rate of 115,137 Boe per day during the fourth quarter of 2014, up 43% over the 2013 fourth quarter due to the continued success of our drilling activity in the play. In 2014, we completed 860 gross (271 net) wells in North Dakota Bakken. Our North Dakota Bakken properties represented 61% of our PV-10 at December 31, 2014 and 60% of our average daily Boe production for the 2014 fourth quarter. Proved reserves in North Dakota Bakken increased 17% year-over-year to 803 MMBoe as of December 31, 2014, of which 35% represents proved developed reserves. Our inventory of proved undeveloped locations stood at 2,355 gross (1,222 net) wells as of December 31, 2014.

Our 2014 drilling activity in North Dakota focused on (1) developing our derisked areas, (2) expanding the field vertically through drilling in the lower benches of the Three Forks formation and horizontally through step-out exploration drilling, (3) pilot density drilling to determine optimum well spacing and patterns for full field development, and (4) testing various enhanced completion technologies to determine optimal methods for maximizing crude oil recoveries and returns. We successfully achieved our 2014 objectives in each of these areas.

In 2013, we initiated a plan to test different areas across the Bakken field to determine what well density and pattern best maximizes crude oil recoveries and returns. In this effort, in 2013 and 2014 we completed seven density pilot projects designed to test the Middle Bakken and Three Forks One, Two and Three benches across a broad section of our North Dakota leasehold. Three of the projects (Hawkinson, Rollefstad, Tangsrud) tested 1,320 foot inter-well spacing and four projects (Wahpeton, Mack, Lawrence, Hartman) tested 660 foot inter-well spacing. We are utilizing the technical data and production results from these projects to guide our future development of the Bakken and Three Forks reservoirs.

Additionally, in 2014 we embarked on a plan to test various enhanced completion technologies and we are monitoring results throughout our Bakken leasehold seeking to maximize crude oil recoveries and returns. The tests included various combinations of fluid types, increased proppant volumes and shorter stimulation stage lengths. In mid-2014, our assessment was expanded to include industry-wide enhanced completion results. The tests completed to date have yielded encouraging results that show solid improvement in well performance and indicate that increased production rates observed early in the life of tested wells may be sustained in certain areas over a one-year time period, which could translate into higher reserve recoveries per well. We continue to study the implications of applying enhanced completion methods across the play and plan to focus our 2015 North Dakota Bakken capital expenditures in areas where improved recoveries are anticipated.

In 2015, we plan to invest approximately $1.5 billion to drill and complete 623 gross (186 net) wells in North Dakota Bakken. The 2015 drilling program will focus on drilling development wells in core areas that provide the opportunity to improve recoveries and rates of return. As of December 31, 2014, we had 20 operated rigs drilling in the North Dakota Bakken and plan to average approximately 11 operated rigs throughout 2015. We plan to operate fewer rigs in North Dakota Bakken in 2015 compared to 2014 levels in order to align our 2015 capital expenditures with lower crude oil prices.

Montana Bakken

Our Montana Bakken properties are located primarily within the Elm Coulee field in Richland County, Montana. Montana Bakken represented 6% of our PV-10 as of December 31, 2014 and 8% of our average daily Boe production for the fourth quarter of 2014. Production in Montana increased to an average rate of 15,646 Boe per day during the fourth quarter of 2014, up 21% over the 2013 fourth quarter due to the continued success of our drilling activity in the play. In 2014, we completed 61 gross (41 net) wells in Montana Bakken. Proved reserves in Montana Bakken increased 20% year-over-year to 63 MMBoe as of December 31, 2014, of which 61% represents proved developed reserves. Our inventory of proved undeveloped drilling locations in Montana Bakken as of December 31, 2014 totaled 99 gross (73 net) wells. In 2015, we plan to invest approximately $15 million completing 8 gross (5 net) wells in Montana Bakken.

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, 2014 and 7% of our average daily Boe production for the fourth quarter of 2014. Our average daily production from these legacy properties decreased 8% in the fourth quarter of 2014 compared to the 2013 fourth quarter due to natural declines in production and reduced drilling activity. Proved reserves totaled 65 MMBoe as of December 31, 2014, nearly all of which are proved developed producing reserves. In 2015, we plan to invest approximately $6 million completing 2 gross (2 net) wells in the Red River units.

North Region Marketing Activities

Crude Oil. We utilize a portfolio approach (pipe and rail) to market our crude oil that began in 2008 with our first shipments of crude oil by rail out of the Williston Basin. We plan to continue pursuing a portfolio approach to balance volumes delivered to pipeline and rail market destinations in an effort to maximize net wellhead value.

Transportation infrastructure continues to improve in the North region with gathering systems picking up crude oil at well site storage tanks with subsequent delivery to railhead or regional pipeline terminals, thereby reducing dependence on truck deliveries. We expect more of our North region crude oil will be shipped in this manner in the coming years.

Natural Gas. Field infrastructure build-out continued in the Williston Basin in 2014 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 2014, we continued to focus on adhering to our natural gas flaring minimization initiatives. For the year ended December 31, 2014, we delivered approximately 87% of our operated natural gas production in North Dakota Bakken to market, flaring approximately 13% compared to an average of 28% flared by industry peers operating in the play. Of the volumes flared in 2014, approximately 3% of our production was flared for reasons within our control. The other 10% of production that was flared in 2014 came from wells already connected to pipeline gathering systems, indicating that operating issues at downstream gathering and processing facilities owned and operated by third parties necessitated the well-site flaring.

South Region

Our properties in the South region represented 26% of our PV-10 as of December 31, 2014 and 25% of our average daily Boe production for the fourth quarter of 2014. For the 2014 fourth quarter, our average daily production from such properties was 48,724 Boe per day, an increase of 36% from the comparable period in 2013. Our principal producing properties in the South region are located in the SCOOP play.

SCOOP

The SCOOP play, discovered by Continental and announced in October 2012, currently extends approximately 120 miles across Garvin, Grady, Stephens, Carter, McClain and Love counties in Oklahoma and contains crude oil and condensate-rich fairways as delineated by numerous industry wells. We are a leading producer, leasehold owner and driller in the SCOOP play. As of December 31, 2014, we controlled the largest leasehold position in SCOOP with approximately 806,800 gross (480,200 net) acres. SCOOP represented 24% of our PV-10 as of December 31, 2014 and 21% of our average daily Boe production for the fourth quarter of 2014. For the year ended December 31, 2014, SCOOP production grew 86% over 2013 due to the continued success of our drilling activity in the play. We completed 151 gross (65 net) wells in SCOOP during 2014. Proved reserves increased 72% year-over-year to 370 MMBoe as of December 31, 2014, of which 23% represents proved developed reserves. Our inventory of proved undeveloped drilling locations in SCOOP as of December 31, 2014 totaled 490 gross (248 net) wells.

Our 2014 drilling program included exploration, step-out and development wells focused on de-risking the play and holding our acreage by production, with an increasing shift toward drilling extended length lateral wells that generate superior economics. The year 2014 was another impactful year for SCOOP as our drilling activities resulted in the vertical expansion of our SCOOP position to include our most recent discovery, the Springer oil play. Located in the heart of our SCOOP acreage, our Springer position supplements our Oklahoma Woodford leasehold and expands our resource potential and inventory in the play. Our SCOOP leasehold has the potential to encounter additional pay from a variety of conventional and potential unconventional reservoirs overlying and underlying the Oklahoma Woodford formation. There are numerous different conventional reservoirs known to produce in the SCOOP area, which have the potential to produce under our SCOOP acreage.

In 2015, we plan to invest approximately $720 million to drill and complete 157 gross (81 net) wells in the SCOOP play. The 2015 drilling program will continue to focus on expanding the known productive extents of the area and de-risking our acreage, while focusing on areas that have the greatest potential to improve recoveries and rates of return. It will also include pilot density projects to determine the optimum well spacing and pattern for full scale development in the future. As of December 31, 2014, we had 23 operated rigs drilling in the SCOOP play and plan to average approximately 16 operated rigs throughout 2015. We plan to operate fewer rigs in SCOOP in 2015 compared to 2014 levels in order to align our 2015 capital expenditures with lower crude oil prices.

Northwest Cana

Our Northwest Cana properties are located in northwestern Oklahoma primarily in Blaine, Dewey and Custer Counties. In recent years, we have undertaken limited drilling activity on our Northwest Cana natural gas properties, choosing instead to allocate capital to areas that generated more attractive rates of return such as the Bakken and SCOOP. Consequently, Northwest Cana represented only 1% of our PV-10 as of December 31, 2014 and 2% of our average daily Boe production for the fourth quarter of 2014. Proved reserves totaled 27 MMBoe as of December 31, 2014, of which 47% represents proved developed reserves. Our inventory of proved undeveloped locations stood at 43 gross (19 net) wells as of December 31, 2014.

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, we sold a 49.9% interest in approximately 44,000 net acres in the Northwest Cana area of the Anadarko Woodford Shale play, along with interests in 37 producing wells. We received approximately $90 million in cash at closing and SK has committed to pay Continental an additional $270 million to fund, or carry, 50% of our remaining share of future drilling and completion costs over a period of approximately five years.

In 2015, we plan to invest approximately $40 million to drill and complete 16 gross (5 net) wells in Northwest Cana within the area of mutual interest established under the agreement with SK. As of December 31, 2014, we had 4 operated rigs drilling in Northwest Cana and plan to average approximately 4 operated rigs throughout 2015.

South Region Marketing Activities

Crude Oil. Due to the proximity of our South region operations to the market center in Cushing, Oklahoma, we typically sell our South region production directly to midstream trading and transportation companies at the wellhead with price realizations that correlate with WTI benchmark pricing. We also plan to deliver a portion of the crude oil production from our SCOOP properties via wellhead pipeline gathering and intrastate pipeline systems directly into

Cushing as field infrastructure is constructed and developed.

Natural Gas. In 2014, 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. 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, 2014, 2013 and 2012 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2014:

	Year ended December 31,		
	2014	2013	2012
Net production volumes:			
Crude oil (MBbls) (1)			
North Dakota Bakken	30,917	23,513	15,936
SCOOP	3,652	2,004	478
Total Company	44,530	34,989	25,070
Natural gas (MMcf)			
North Dakota Bakken	33,610	26,783	16,454
SCOOP	55,017	29,438	7,060
Total Company	114,295	87,730	63,875
Crude oil equivalents (MBoe)			
North Dakota Bakken	36,518	27,977	18,679
SCOOP	12,822	6,910	1,654
Total Company	63,579	49,610	35,716
Average sales prices: (2)			
Crude oil ($/Bbl)			
North Dakota Bakken	$80.22	$89.45	$84.50
SCOOP	87.58	95.63	89.37
Total Company	81.26	89.93	84.59
Natural gas ($/Mcf)			
North Dakota Bakken (3)	$6.63	$5.94	$5.20
SCOOP (3)	5.23	5.25	3.82
Total Company (3)	5.40	4.87	3.73
Crude oil equivalents ($/Boe)			
North Dakota Bakken (3)	$73.96	$80.87	$76.64
SCOOP (3)	47.35	50.08	33.01
Total Company (3)	66.53	72.04	65.99
Average costs per Boe: (2)			
Production expenses ($/Boe)			
North Dakota Bakken	$5.67	$5.50	$4.31
SCOOP	1.13	0.99	1.02
Total Company	5.58	5.69	5.49
Production taxes and other expenses ($/Boe) (3)	$5.54	$6.02	$5.58
General and administrative expenses ($/Boe) (4)	$2.92	$2.91	$3.42
DD&A expense ($/Boe)	$21.51	$19.47	$19.44

(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 408 MBbls less than production volumes for 2014, 4 MBbls less than production volumes for 2013, and 112 MBbls less than production volumes for 2012.

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

(3) Prior to 2014 we presented charges related to natural gas transportation and processing in the caption "Production taxes and other expenses" in our consolidated statements of comprehensive income. Effective January 1, 2014, such charges are netted within "Crude oil and natural gas sales". Average sales prices and per unit costs for 2013 and 2012 have been adjusted, as applicable, to conform to the current year presentation. Reclassified amounts for the total Company amounted to $33.3 million ($0.67 per Boe) for 2013 and $29.9 million ($0.84 per Boe) for 2012.

(4) General and administrative expense ($/Boe) includes non-cash equity compensation expenses of $0.86 per Boe, $0.80 per Boe, and $0.82 per Boe for 2014, 2013 and 2012, respectively, and corporate relocation expenses of $0.04 per Boe and $0.22 per Boe for 2013 and 2012, respectively.

The following table sets forth information regarding our average daily production by region during the fourth quarter of 2014:

	Fourth Quarter 2014 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	96,220	113,500	115,137
Montana Bakken	13,758	11,327	15,646
Red River units			
Cedar Hills	9,504	2,271	9,883
Other Red River units	2,941	2,610	3,376
Other	145	3,272	690
South Region:			
SCOOP	13,130	163,643	40,403
Northwest Cana	341	20,635	3,780
Arkoma Woodford	4	13,886	2,318
Other	929	7,763	2,223
Total	136,972	338,907	193,456

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, 2014. 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	3,117	1,049	1	—	3,118	1,049
Montana Bakken	421	273	2	1	423	274
Red River units						
Cedar Hills	137	131	—	—	137	131
Other Red River units	137	123	—	—	137	123
Other	1	1	16	4	17	5
South Region:						
SCOOP	100	65	199	81	299	146
Northwest Cana	4	3	170	61	174	64
Arkoma Woodford	1	—	390	58	391	58
Other	199	153	195	97	394	250

Total	4,117	1,798	973	302	5,090	2,100

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Title to Properties

As is customary in the crude oil and natural gas industry, upon initiation of fee leasing of undeveloped leasehold which does not have associated proved reserves, contract landmen conduct a title examination of courthouse records. Such title examinations are reviewed and approved by Company landmen. Prior to closing an acquisition from a third party, whether 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 procure an acquisition title opinion depending on the materiality of the properties involved.

Prior to the commencement of drilling operations on a property, we may procure a title opinion from external legal counsel or perform curative work to satisfy requirements pertaining to material title defects. We may choose not to commence drilling operations on a property until we have cured material title defects as to the Company's interest on such property.

We have procured and cured title opinions 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 other interests and other 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 end users at major market centers. Other production not sold at major market centers is sold to select 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 the most practical point on a pipeline system for delivery to a sales point “downstream” on another connecting pipeline. Crude oil sold at the lease is delivered directly onto the purchaser’s truck and the sale is complete at that point.

We have a strategic mix of gas transport, processing and sales arrangements for our natural gas production. A majority of our natural gas production is sold at the wellhead, with the remainder being sold at various points downstream under monthly interruptible packaged-volume deals, short-term seasonal packages, and long-term multi-year acreage dedication type contracts. All of our natural gas is sold at market. Some of our contracts allow us the flexibility to sell at the well or, with notice, take our gas “in-kind”, transport, process, and sell in the market area. Midstream natural gas gathering and processing companies are our primary transporters and purchasers. We continue to develop relationships and have potential future contracts with end-use customers including utilities, industrial and liquefied natural gas exporters.

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 facilities, most of which are owned by third parties, and on the availability of rail transportation.

For the year ended December 31, 2014, sales to Marathon Crude Oil Company and PBF Holding Company LLC accounted for approximately 14% and 11%, respectively, 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 2014. 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 our producing 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. In addition, shortages or the high cost of drilling rigs, equipment or other services could delay or adversely affect our development and exploration operations. 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.

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 and its members 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, consequently, affect profitability. We believe we are in substantial compliance with all laws and regulations and policies currently applicable to us and our continued compliance with existing requirements will not have a material adverse impact on us. However, because public policy changes affecting the crude oil and natural gas industry are commonplace and because laws and regulations may be enacted, amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws 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 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. The United States regulates the exportation of petroleum and petroleum products, and these regulations could restrict the markets for these commodities and thus affect sales prices. Regulations restricting the exportation of domestically produced petroleum products date back to the 1970s. Certain U.S. lawmakers are considering initiating legislation aimed at amending or removing the export restrictions. Additionally, the President of the United States could lift the export restrictions by executive order and the Bureau of Industry and Security of the U.S. Department of Commerce could issue crude oil export licenses. At this time, the enactment of any such legislation or actions and the potential impact on commodity markets and sales prices is uncertain.

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." Should 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 36% of such production being shipped by rail in December 2014. 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. In addition, 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 in ways 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 over the past year 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 they 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 August 2014, PHMSA issued a Notice of Proposed Rulemaking proposing, among other things, additional requirements to enhance tank car standards for certain trains carrying crude oil and ethanol, a classification and testing program for crude oil, and a requirement that older DOT-111 tank cars be phased out by as early as October 1, 2017 if they are not retrofitted to comply with new tank car design standards. The final rule is expected in the first half of 2015. In conjunction with the proposed rule, PHMSA published an Advanced Notice of Proposed Rulemaking related to potential revisions to its regulations to expand the applicability of comprehensive oil spill response plans to certain trains based on the thresholds of crude oil that apply to an entire train.

We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any 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. At this time, it is not possible to estimate the potential impact on our business if new federal or state rail transportation regulations are enacted.

At the state level, in December 2014 the North Dakota Industrial Commission ("NDIC") implemented 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 take effect on April 1, 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 cause our cost of doing business in North Dakota to increase, 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." Should 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 addition, certain banking regulators and the CFTC have proposed rules to establish minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce our liquidity and cash available for capital expenditures and could reduce our ability to manage commodity price volatility and the volatility in our cash flows.

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 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. The SEC did not appeal the ruling and has stated it plans to issue a revised proposal, the timing of which is uncertain.

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 as described further below.
The EPAct 2005 also provided the FERC with additional civil penalty authority. The EPAct 2005 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. Under EPAct 2005, the FERC also has 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. The Rule also bans intentional failures to state a material fact when the omission makes a statement misleading or distorts, or is likely to distort, market conditions for any product covered by the Rule. The FTC holds substantial enforcement authority under the EISA, including authority to request a court to impose fines of up to $1,000,000 per day per violation. Under the Commodity Exchange Act, the CFTC is directed to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to 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 materially differently than our similarly situated competitors.

Environmental, health and safety regulation

General. We are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, health and safety, including the discharge of materials into the environment. These laws 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 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 initiatives. We are committed to conducting our operations in a manner that protects the health, safety and welfare of the public, our employees and the environment. We strive to operate in accordance with all applicable regulatory requirements and have focused on continuously improving our health, safety, security and environmental ("HSS&E") performance. We believe excellent HSS&E performance is critical to the long-term success of our business, and is a key component in maximizing return to shareholders. We also believe achieving this excellence requires the commitment and involvement of all employees in the Company, and we expect the same level of commitment from our contractors and vendors. Our commitment to HSS&E excellence is a paramount objective.

In connection with our HSS&E initiatives, we actively work to identify and manage the environmental and safety risks and the impact of our operations. Further, we set corporate objectives aimed at producing continuous improvement of our HSS&E efforts and we seek to provide the leadership and resources to enable our workforce to achieve our objectives. We routinely monitor our HSS&E performance to assess our conformity with environmental protection and safety initiatives.

We take a proactive and disciplined approach to emergency preparedness and business continuity planning to address the health, safety, security, and environmental risks inherent to our industry. We engage in ongoing training of our workforce and conduct drills to improve awareness and readiness to mitigate such risks. Further, emergency response plans are maintained that establish procedures to be utilized during various types of emergencies affecting our personnel, facilities or the environment.

One ongoing focus of our HSS&E initiatives is the reduction of air emissions produced from our operations, particularly with respect to flaring natural gas from our operated well sites in the Bakken field of North Dakota, our most active area. The rapid growth of crude oil production in North Dakota in recent years, coupled with a lack of established natural gas transportation infrastructure in the state, has led to an industry-wide increase in flaring of natural gas produced in association with crude oil production. 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 either 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. If an unconnected well is not capped, exempted, or utilizing an acceptable alternative for capturing a percentage of the flared gas, then the producer is required to pay royalties and production taxes on the value of flared gas, as determined by the NDIC. Further, 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. While the NDIC has thus far generally accepted our gas capture plans submitted with applications for drilling permits, and our proposed methods for valuing and calculating taxes and royalties on flared gas, the requirements for obtaining permits to drill, exemptions from post-year flaring restrictions, and determinations of volumes and value for royalty calculation on flared gas remain uncertain and subject to change.

We recognize the environmental and financial risks associated with natural gas flaring and manage these risks on an ongoing basis. We set internal flaring reduction targets and to date 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. Our ultimate goal is to reduce natural gas flaring from our operated well sites to as close to zero percent flaring as possible. 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 and minimize impacts to the environment.

For the year ended December 31, 2014, we delivered approximately 87% of our operated natural gas production in North Dakota Bakken to market, flaring approximately 13% compared to 11% in 2013, 15% in 2012 and 19% in 2011. Of the volumes flared in 2014, approximately 3% of our production was flared for reasons within our control. The other 10% of production flared in 2014 came from wells already connected to pipeline gathering systems, indicating that operating issues at downstream gathering and processing facilities owned and operated by third parties necessitated the well-site flaring.

We believe maintaining our low level of flaring is a notable accomplishment given the significant increase in our natural gas production in the Bakken field, including areas with limited gas gathering infrastructure. Flaring from our operated well sites in North Dakota Bakken is significantly less than our industry peers operating in the play. According to data published by the NDIC, our industry as a whole flared approximately 28% of produced natural gas volumes in the state during 2014. We are a participant in the NDIC's Flaring Reduction Task Force and are actively engaged in working with other task force members and the NDIC to develop action plans for mitigating natural gas flaring in the state.

We are experiencing similar or better flaring results in our other key operating areas outside of North Dakota. In the Montana Bakken, we flared approximately 10% (5% within our control) of the natural gas produced from our operated well sites in 2014. Additionally, flared natural gas volumes from our operated SCOOP and Northwest Cana properties in Oklahoma are negligible given the existence of established natural gas transportation infrastructure in that state. Through our HSS&E initiatives, we will continue to work toward maintaining an industry-leading position with respect to flaring reduction efforts in North Dakota and our other key operating areas. Our flaring reduction progress is 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, among other factors.

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 or results of operations.

Environmental, health and safety laws and regulations. Some of the existing environmental, health and safety laws 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 plugging operations to prevent future contamination; (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, or 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 the 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 federal Occupational Safety and Health 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 (xiii) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material.

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. These effects are widely referred to as “climate change.” In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration (“PSD”), construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for the greenhouse gas emissions also will be 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. 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. More recently, in January 2015, the Obama Administration announced the EPA is expected to propose in the summer of 2015 and finalize in 2016 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 Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025.

In April 2012, the EPA issued final rules establishing new air emission controls for crude oil and natural gas production and natural gas processing operations under the 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 (“VOCs”) 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 flow back 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 VOC, 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.

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 those greenhouse gas. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such 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 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.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

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. Recently there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies and to cause earthquakes. As a result, several federal 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. 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, the EPA has announced its intention to propose regulations under the CWA sometime in 2015 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. Moreover, the EPA is conducting a study of the potential impacts of hydraulic fracturing activities on water resources and a draft final report is anticipated sometime in 2015 for peer review and public comment. The results of this 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 proposed rules in May 2013 to update existing regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. A final version of these rules may be adopted in 2015.

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 government 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. We currently disclose the additives used in the hydraulic fracturing process on all wells we operate.

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 control 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 wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. In response to these concerns, regulators in some states are considering additional requirements related to seismic safety. 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 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 control wells which could cause us to delay, curtail or discontinue our exploration and development plans. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability; however, these costs are commonly incurred by all oil and gas producers and we do not believe that 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.

Employees

As of December 31, 2014, we employed 1,188 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.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows, and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

A substantial or extended decline in crude oil and natural gas prices would adversely affect our business, financial condition, results of operations or cash flows and our ability to meet our capital expenditure needs and financial commitments.

The price we receive for our crude oil and natural gas production heavily influences our revenue, profitability, access to capital, capital budget and future rate of growth. Crude oil and natural gas are commodities and, therefore, 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 prices in the third and fourth quarters of 2014, and which continued into early 2015. Historically, the markets for crude oil and natural gas have been volatile; for example, the NYMEX West Texas Intermediate crude oil and Henry Hub natural gas spot prices ranged from $53.45 to $107.95 per barrel and $2.74 to $8.15 per MMBtu, respectively, during 2014. Crude oil and natural gas prices are likely to remain volatile in 2015.

In the fourth quarter of 2014, following a decrease in crude oil prices and related increase in the fair value of our derivative assets, substantially all of our outstanding crude oil derivative contracts for periods subsequent to December 31, 2014 were settled prior to the expiration of their contractual maturities, resulting in the receipt of cash proceeds totaling approximately $433 million. Consequently, our crude oil production and sales for 2015 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

The prices we receive for 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 and effect of trading in commodity futures markets;
- the price and quantity of imports of foreign crude oil;
- the potential export 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;
- the level of national and global crude oil and natural gas exploration and production;
- the level of national and global crude oil and natural gas inventories;
- localized supply and demand fundamentals;
- the availability, proximity and capacity of transportation, processing, storage and refining facilities;
- changes in supply, demand, and refinery capacity for various grades of crude oil and natural gas;
- the ability of refineries in the United States to accommodate increasing 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.

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Sustained declines in crude oil and natural gas prices may: (i) reduce our cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; (ii) limit our ability to borrow money or raise additional capital; and (iii) reduce the amount of crude oil and natural gas we can economically produce.
Substantial, extended decreases in crude oil and natural gas prices may cause us to delay or postpone a significant portion of our exploration, development and exploitation projects or may render such projects uneconomic. This may result in significant downward adjustments to our estimated proved reserves and may lead to a downgrade or other negative rating action with respect to our credit rating. A downgrade of our credit rating could negatively impact our cost of capital and our ability to access capital markets, increase our costs under our credit facility, and limit our ability to execute aspects of our business plans. As a result, a substantial or extended decline in crude oil or natural gas prices would materially and adversely affect our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments.
A substantial portion of our producing properties are located in the North region, making us vulnerable to risks associated with having operations concentrated in this geographic area.
Our operations are geographically concentrated in the North region, with that region comprising approximately 74% of our crude oil and natural gas production and approximately 83% of our crude oil and natural gas revenues for the year ended December 31, 2014. Additionally, as of December 31, 2014 approximately 69% of our estimated proved reserves were located in the North region. Our principal producing properties in the North region are located in the Bakken field of North Dakota and Montana.
Because of this geographic concentration, 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 region 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 North region may be adversely affected by severe weather events such as floods and blizzards, 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 the North region 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 region such as natural disasters, industrial accidents or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, 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 spending. In recent periods, there has been significant downward pressure on oil prices, and a continuation of that trend could continue or exacerbate that pressure. This would negatively impact our revenues, margins, profitability, operating cash flows, liquidity and financial condition. Such weakness or uncertainty could also cause our natural gas hedging arrangements or future crude oil hedges, if any, to become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Furthermore, our ability to collect receivables may be adversely impacted.
Historically, we have used cash flows from operations, borrowings under our 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 result in our inability to obtain needed capital on acceptable terms or at all and may increase our cost of financing. We have a credit facility with lender commitments totaling $2.5 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 credit facility if our lenders are unwilling or unable to meet their funding obligations or increase their commitments as required 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 2014, we invested approximately $5.02 billion in our capital program, inclusive of property acquisitions. We have budgeted $2.70 billion for capital expenditures in 2015 (excluding acquisitions which are not budgeted) of which $2.48 billion is allocated for drilling, capital workovers and facilities. Our 2015 capital expenditures are substantially lower than such expenditures in 2014 as a result of lower commodity prices. We may find that additional reductions are prudent depending on market conditions.

Historically, our capital expenditures have been financed with cash generated by operations, borrowings under our 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 amount 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.

If revenues or our ability to borrow decrease significantly, we may have limited ability to obtain the capital necessary to sustain our operations at planned levels. If cash generated by operations or cash available under our credit facility is not sufficient to meet capital requirements, 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 and our ability to achieve our growth plans.

We intend to finance future capital expenditures primarily through cash flows from operations and borrowings under our 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 beyond our control, 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;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- decreases in 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, 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 may 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 the recent significant decline in commodity prices.

The process of estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of available technical data and many assumptions, including assumptions relating to current and future economic conditions, production rates, drilling and operating expenses, and commodity prices. Any significant inaccuracy in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves for information about our estimated crude oil and natural gas reserves, PV-10, and Standardized Measure of discounted future net cash flows as of December 31, 2014.

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 could result in fluctuations in reserves between periods as reserves booked in one period may need to be removed in a subsequent period.

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 with the uncertainty of decline curves and the ability to model heterogeneity of 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, in accordance with SEC requirements, calculated by determining the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding 12 months. For the 12-months ended December 31, 2014, average prices used to calculate our estimated proved reserves were $94.99 per Bbl for crude oil and $4.35 per MMBtu for natural gas ($84.54 per Bbl for crude oil and $6.06 per Mcf for natural gas adjusted for location and quality differentials). Commodity prices declined significantly in the fourth quarter of 2014 and if such prices do not increase significantly, our future calculations of estimated proved reserves will be based on lower commodity 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 commodity prices used in our year-end reserve estimates were decreased by $40.00 per Bbl for crude oil and $1.00 per Mcf for natural gas, thereby approximating the pricing environment existing in February 2015, our proved reserves at December 31, 2014 could decrease by approximately 10%.

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, 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 recent 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. In accordance with SEC rules, 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 SEC pricing 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 10% discount factor we use when calculating discounted future net revenues 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, 2014, the PV-10 value of our proved reserves totaled approximately $22.8 billion. The average prices used to estimate our proved reserves and PV-10 at December 31, 2014, as calculated in accordance with SEC rules, were $94.99 per Bbl for crude oil and $4.35 per MMBtu for natural gas ($84.54 per Bbl for crude oil and $6.06 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. If crude oil prices decline by $10.00 per barrel from those used in our year-end estimates, our PV-10 as of December 31, 2014 could decrease approximately $3.2 billion, or 14%. If natural gas prices decline by $1.00 per Mcf from those used in our year-end estimates, our PV-10 as of December 31, 2014 could decrease approximately $1.7 billion, or 8%.

Commodity prices have decreased significantly in recent months. Holding all other factors constant, if commodity prices used in our year-end reserve estimates were decreased by $40.00 per Bbl for crude oil and $1.00 per Mcf for natural gas, thereby approximating the pricing environment existing in February 2015, our PV-10 at December 31, 2014 could decrease by approximately $13.8 billion, or 61%.

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

Accounting rules require that we periodically review the carrying values of our crude oil and natural gas properties for possible impairment. 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 crude oil 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. Such shortages or costs could delay the execution of our drilling plans or cause us to incur significant 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.

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; and
- repair and remediation costs.

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 we face 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.

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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 that will require substantial additional seismic data processing and interpretation. It is not possible to predict with certainty in advance of drilling and testing 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. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including 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 in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if the 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 crude oil prices, reduced capital spending and numerous other factors, many of which are beyond our control, could result in our failure to establish production on undeveloped acreage, and, if we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 66% of our total net undeveloped acreage at December 31, 2014. At that date, we had leases representing 410,481 net acres expiring in 2015, 345,612 net acres expiring in 2016, and 271,597 net acres expiring in 2017. 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, 2014, approximately 63% of our total estimated proved reserves (by volume) were undeveloped and may not be ultimately developed or produced. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve estimates assume we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove to be accurate. Our reserve report at December 31, 2014 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $12.2 billion. We cannot be certain the estimated costs of the development of these reserves are accurate, that development will occur as scheduled, or that the results of such development will be as estimated. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC’s reserve rules, because proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any proved undeveloped reserves not developed within this five-year time frame. A removal of such reserves could adversely affect our operations. In 2014, 105 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.

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 marketability of 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 product, 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 to deliver the products to market.

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, changes in tax and energy policies, federal and state 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 market and deliver our products or 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 what prices would be charged. 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 36% of such production being shipped by rail in December 2014. 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 that could potentially impact the transportation of crude oil by rail. The introduction of regulations, including voluntary measures adopted by the railroad industry, that result in new requirements addressing 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 new specifications. We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any 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 water. 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 control wells.

In addition, concerns have been raised about the potential for earthquakes to occur from the use of underground injection control 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 in others. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of water necessary for hydraulic fracturing of wells or the disposal of 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 these 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. For instance, one of our prospects in Texas in the early stages of exploration and development has not yielded sufficient reserves and production to achieve a satisfactory economic return, which resulted in $58 million of proved property impairments and $92 million of unproved property impairments being recognized for the prospect in 2014.

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 that can be 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 findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet “best available control technology” standards that will be 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. 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. More recently, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025.

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 climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the

overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.
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, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, 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. Recently there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies and increase the potential for earthquakes. 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 SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014. In addition, 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, the EPA has announced its intention to propose regulations under the CWA sometime in 2015 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. The EPA is also conducting a study of the potential environmental impacts of hydraulic fracturing on water resources and a draft final report is anticipated sometime in 2015 for peer review and public comment. The results of this study or similar governmental reviews could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Further, the Bureau of Land Management issued a revised proposed rule in May 2013 that would require public disclosure of chemicals used in hydraulic fracturing operations, and impose other operational requirements for all hydraulic fracturing operations on federal lands, including Native American trust lands. As of December 31, 2014, we held approximately 209,800 net undeveloped acres on federal land, representing approximately 14% of our total net undeveloped acres.

At the state level, several states, including states in which we operate, have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local government 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 that 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. This would have a material adverse effect on our business and would impair our ability to implement our growth plans.

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 limitations and restrictions on hydraulic fracturing of wells, 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 liquidity, delay operations or otherwise alter the way we conduct our business. This, in turn, could have a material adverse effect on our financial condition, results of operations and cash flows.

Certain federal income tax deductions currently available with respect to crude oil and natural gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in President Obama’s fiscal year 2016 budget proposal are the elimination or deferral of certain key 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 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. These proposed changes, if enacted, may negatively affect our financial condition and results of operations. The passage of legislation in response to President Obama’s 2016 budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain available tax deductions within the industry with respect to crude oil and natural gas exploration and development, and any such changes could negatively affect our cash flows available for capital expenditures and our ability to achieve our growth plan.

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 calls for the establishment of margin requirements for uncleared swaps, which have not been finalized. 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.

If we do not qualify for the end user exemption from any applicable clearing requirements, the new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), 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, the margin requirements for uncleared swaps if enacted 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 commodity 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. The cost to attract and retain qualified personnel has increased in recent years due to competition and may increase substantially in the future. 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, 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 interest are operated by other companies and involve third-party working interest owners. As of December 31, 2014, non-operated properties represented 22% of our estimated proved developed reserves, 14% of our estimated proved undeveloped reserves, and 17% of our estimated total proved reserves. We have limited ability to influence or control the operations or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures required to fund the development of such properties. Moreover, we are dependent on the other working interest owners on these projects to fund their contractual share of the capital 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 credit facility and the 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 credit facility contains restrictive covenants that 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.

At December 31, 2014, our consolidated net debt to total capitalization ratio, as defined in the credit facility, was 0.55 to 1.00. Our total debt would need to independently increase by approximately $3.25 billion, or 54%, above existing levels at December 31, 2014 (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 $1.75 billion, or 35%, below existing levels at December 31, 2014 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 credit facility and senior note indentures may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our credit facility or senior note indentures may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our credit facility or senior note indentures, in which case, depending on the actions taken by the lenders or trustees thereunder or their successors or assignees, could result in all amounts outstanding thereunder, together with accrued interest, to be due and payable. If our indebtedness is accelerated, our assets may not be sufficient to repay in full such indebtedness, which would adversely affect our financial condition and results of operations.

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. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flows used for drilling and place us at a competitive disadvantage. For example, as of February 17, 2015, outstanding borrowings under our credit facility were $605 million and the impact of a 1% increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $6.1 million and a $3.8 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 our significant customers 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, refineries and affiliates ($566 million in receivables at December 31, 2014); our joint interest receivables ($568 million at December 31, 2014); and counterparty credit risk associated with our derivative instrument receivables ($84 million at December 31, 2014). 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 several significant customers. The two largest purchasers of our crude oil and natural gas during the year ended December 31, 2014 accounted for a combined 25% of our total crude oil and natural gas revenues for the year. We generally do not require 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. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition, results of operations and cash flows.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in 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 crude oil and natural gas commodity derivative positions. We do not designate any of our derivative instruments as hedges for accounting purposes and we record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

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. In the fourth quarter of 2014, following a decrease in crude oil prices and related increase in the fair value of our derivative assets, substantially all of our outstanding crude oil derivative contracts were settled prior to the expiration of their contractual maturities, resulting in the receipt of cash proceeds totaling approximately $433 million. Consequently, our crude oil production and sales for 2015 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

Our Chairman and Chief Executive Officer owns approximately 68% 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, 2014, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owned 252,956,381 shares of our outstanding common stock, representing approximately 68% of our outstanding common shares. As a result, Mr. Hamm is our controlling shareholder 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. As controlling shareholder, Mr. Hamm could cause, delay or prevent a change of control of our Company. The interests of Mr. Hamm may not coincide with the interests of other holders of our common stock.

Mr. Hamm has controlled in the past, and may control in the future, companies engaged in the business of gathering, processing, and marketing crude oil and natural gas or providing oilfield services in some of the areas where we have operations. We have historically entered into, and may enter into, transactions from time to time with affiliated companies 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 can provide no assurance that any such conflicts will be resolved in our favor.

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 their 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 may become 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:

- 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 infrastructure could result in 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 a third party gathering, pipeline, or rail service provider could delay or prevent us from 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 date we have not experienced any material losses relating to cyber attacks; however, there can be no assurance that we will not suffer such 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, 2014.

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, an alleged class action was filed against the Company alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners as categorized in the petition from crude oil and natural gas wells located in Oklahoma. The plaintiffs have 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 alleged class. The Company has responded to the petition, denied the allegations and raised a number of affirmative defenses. Discovery is ongoing and information and documents continue to be exchanged. 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. The class has not been certified. The class certification hearing is currently scheduled for May 25, 2015. Plaintiffs have indicated that if the class is certified they may seek damages in excess of $165 million 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 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 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. Sales prices presented below have been retroactively adjusted, as applicable, to reflect our 2-for-1 stock split occurring in September 2014. No cash dividends were declared during the previous two years.

	2014				2013			
	Quarter Ended				Quarter Ended			
	March 31	June 30	September 30	December 31	March 31	June 30	September 30	December 31
High	$63.23	$79.44	$80.91	$67.25	$47.00	$44.82	$54.10	$60.89
Low	$52.00	$60.51	$65.22	$30.06	$37.02	$36.18	$43.28	$50.13
Cash Dividend	—	—	—	—	—	—	—	—

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. As of February 6, 2015, the number of record holders of our common stock was 745. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 73,400. On February 17, 2015, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $48.67 per share.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2014:

Period	Total number of shares purchased	Average price paid per share	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, 2014 to October 31, 2014	—	—	—	—
November 1, 2014 to November 30, 2014	166,120 (1)	$53.97 (2)	—	—
December 1, 2014 to December 31, 2014	—	—	—	—
Total	166,120	$53.97	—	—

(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 Company's 2005 Plan. Restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms. These shares purchased 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, 2014 relating to equity compensation plans:

	Number of Shares to be Issued Upon	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity

	Exercise of Outstanding Options		Compensation Plans (1)
Equity Compensation Plans Approved by Shareholders	—	—	18,104,686
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 2009 through December 2014. The graph assumes the value of the investment in our common stock and in each index was $100 on December 31, 2009 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, 2010 through 2014. 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. Shares and earnings per share amounts for 2010 through 2013 have been retroactively adjusted to reflect our 2-for-1 stock split occurring in September 2014. 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,				
	2014	2013	2012	2011	2010
Income Statement data					
In thousands, except per share data					
Crude oil and natural gas sales (1)	$4,203,022	$3,573,431	$2,349,500	$1,633,718	$942,989
Gain (loss) on derivative instruments, net (2)	559,759	(191,751)	154,016	(30,049)	(130,762)
Total revenues (1)	4,801,618	3,421,807	2,542,587	1,636,088	833,530
Income from continuing operations	977,341	764,219	739,385	429,072	168,255
Net income	977,341	764,219	739,385	429,072	168,255
Basic earnings per share:					
From continuing operations	$2.65	$2.08	$2.04	$1.21	$0.50
Net income per share	$2.65	$2.08	$2.04	$1.21	$0.50
Shares used in basic earnings per share	368,829	368,150	362,680	355,180	337,970
Diluted earnings per share:					
From continuing operations	$2.64	$2.07	$2.03	$1.20	$0.50
Net income per share	$2.64	$2.07	$2.03	$1.20	$0.50
Shares used in diluted earnings per share	370,758	369,698	363,692	356,460	339,558
Production					
Crude oil (MBbl) (3)	44,530	34,989	25,070	16,469	11,820
Natural gas (MMcf)	114,295	87,730	63,875	36,671	23,943
Crude oil equivalents (MBoe)	63,579	49,610	35,716	22,581	15,811
Average sales prices (4)					
Crude oil ($/Bbl)	$81.26	$89.93	$84.59	$88.51	$70.69
Natural gas ($/Mcf)	$5.40	$4.87	$3.73	$4.87	$4.26
Crude oil equivalents ($/Boe)	$66.53	$72.04	$65.99	$72.45	$59.35
Average costs per unit (4)					
Production expenses ($/Boe)	$5.58	$5.69	$5.49	$6.13	$5.87
Production taxes (% of oil and gas revenues)	8.2%	8.3%	8.3%	8.0%	7.5%
DD&A ($/Boe)	$21.51	$19.47	$19.44	$17.33	$15.33
General and administrative expenses ($/Boe) (5)	$2.92	$2.91	$3.42	$3.23	$3.09
Proved reserves at December 31					
Crude oil (MBbl)	866,360	737,788	561,163	326,133	224,784
Natural gas (MMcf)	2,908,386	2,078,020	1,341,084	1,093,832	839,568
Crude oil equivalents (MBoe)	1,351,091	1,084,125	784,677	508,438	364,712

Other financial data (in thousands)					
Net cash provided by operating activities	$3,355,715	$2,563,295	$1,632,065	$1,067,915	$653,167
Net cash used in investing activities	$(4,587,399)	$(3,711,011)	$(3,903,370)	$(2,004,714)	$(1,039,416)
Net cash provided by financing activities	$1,227,715	$1,140,469	$2,253,490	$982,427	$379,943
EBITDAX (6)	$3,776,051	$2,839,510	$1,963,123	$1,303,959	$810,877
Total capital expenditures	$5,015,595	$3,841,633	$4,358,572	$2,224,096	$1,237,189
Balance Sheet data at December 31 (in thousands)					
Total assets	$15,145,070	$11,941,182	$9,140,009	$5,646,086	$3,591,785
Long-term debt, including current maturities	$5,997,915	$4,715,832	$3,539,721	$1,254,301	$925,991
Shareholders’ equity	$4,967,844	$3,953,118	$3,163,699	$2,308,126	$1,208,155

(1) Prior to 2014 we presented charges related to natural gas transportation and processing in the caption "Production taxes and other expenses" in our consolidated statements of comprehensive income. Effective January 1, 2014, such charges are netted within "Crude oil and natural gas sales" and consequently "Total revenues". Crude oil and natural gas sales and total revenues reflected above for 2010 through 2013 have been adjusted to conform to the current year presentation. Reclassified amounts total $33.3 million, $29.9 million, $13.7 million, and $5.5 million for the years ended December 31, 2013, 2012, 2011, and 2010, respectively.

(2) 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 $174.4 million, ($130.2) million, $199.7 million, $4.1 million and ($166.2) million for the years ended December 31, 2014, 2013, 2012, 2011, and 2010, 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 scheduled through December 2016.

(3) At various times, we have stored crude oil due to pipeline line fill requirements, low commodity prices, or marketing disruptions or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes. 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. For 2010, crude oil sales volumes were 78 MBbls more than crude oil production volumes.

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

(5) General and administrative expenses ($/Boe) include non-cash equity compensation expenses of $0.86 per Boe, $0.80 per Boe, $0.82 per Boe, $0.73 per Boe, and $0.74 per Boe for the years ended December 31, 2014, 2013, 2012, 2011, and 2010, 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.

(6) 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.

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 play in Oklahoma.

Business Environment and Outlook

Crude oil prices decreased significantly in the latter part of 2014 and have continued to trend lower in 2015, dropping to the lowest levels since March 2009. Management's plans and related capital projections for 2015 are reflective of lower commodity prices. The Company remains confident of its underlying financial strength to manage the challenges presented in the current pricing environment.

In response to the decrease in crude oil prices, we have significantly reduced our 2015 capital expenditures budget to $2.70 billion, nearly half the amount spent in 2014. We expect our operated rig count to average 31 rigs for full-year 2015, down from 49 operated rigs at December 31, 2014.

While we plan to scale back our 2015 drilling, we plan to continue the momentum of our long-term growth projects in North Dakota Bakken and SCOOP by focusing our drilling efforts in core areas of those plays that have the greatest potential to improve recoveries and rates of return. Our planned drilling activity for 2015 is projected to yield 16% to 20% production growth compared to 2014.

Our 2015 capital budget has been established based on an expectation of available cash flows from operations and availability under our credit facility. We will continue to monitor our capital spending closely based on actual and projected cash flows and could scale back our 2015 spending further should commodity prices remain at current levels or fall further. Conversely, a significant improvement in crude oil prices could result in an increase in our capital expenditures.

We believe we are positioned to withstand the current weakness in crude oil prices. The depth and quality of our asset base coupled with our financial strength allow us to be adaptable in a variety of price environments.

2014 Highlights

Proved reserves

At December 31, 2014, our estimated proved reserves totaled 1,351 MMBoe, an increase of 25% over proved reserves of 1,084 MMBoe at December 31, 2013. Extensions and discoveries were the primary drivers of our reserves growth in 2014, adding 441 MMBoe of proved reserves during the year mainly from successful drilling results in the Bakken field and SCOOP play. The Bakken field comprised 64% of our proved reserves at December 31, 2014, with SCOOP comprising 27%.

Proved reserves in the Bakken field totaled 866 MMBoe at December 31, 2014, an increase of 17% from 741 MMBoe at year-end 2013 driven by the completion of 921 gross (312 net) wells during the year.

Proved reserves in the SCOOP play increased 72% from 215 MMBoe at December 31, 2013 to 370 MMBoe at year-end 2014 through the completion of 151 gross (65 net) wells during the year. 2014 was another impactful year for SCOOP as our drilling activities resulted in the vertical expansion of our SCOOP position to include our most recent discovery, the Springer oil play.

Crude oil comprised 64%, or 866 MMBoe, of our proved reserves at December 31, 2014 compared to 68% at year-end 2013. The decreased percentage of crude oil reserves resulted from the significant 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 our other operating areas such as the Bakken.

The decrease in crude oil prices in late 2014 did not have a significant impact on the 12-month average SEC prices used in our year-end reserve estimates and therefore did not result in significant downward reserve revisions at December 31, 2014. We did, however, remove certain proved undeveloped reserves due to changes in drilling plans in response to lower crude oil prices as discussed in Part I, Item 1. Business—Crude Oil and Natural Gas Operations—Proved Reserves. Significant downward reserve revisions may occur in 2015 if the currently depressed pricing environment for crude oil persists or worsens.

Production

Crude oil and natural gas production totaled 63,579 MBoe (174,189 Boe per day) in 2014, representing a 28% increase over 2013. Crude oil production increased 27% in 2014 and natural gas production increased 30%. Crude oil represented 70% of our 2014 production compared to 71% for 2013.

Production for the fourth quarter of 2014 totaled 17,798 MBoe (193,456 Boe per day), a 6% increase over the third quarter of 2014 and 34% higher than the fourth quarter of 2013. Crude oil represented 71% of our production for the 2014 fourth quarter. We reached a production milestone of 200,000 Boe per day in late December 2014.

The increases in fourth quarter and full year 2014 production were primarily driven by higher production from our properties in the Bakken field and SCOOP play due to the continued success of our drilling programs in those areas. Our total Bakken production increased to 41,871 MBoe (114,715 Boe per day) for 2014, a 30% increase over 2013. Fourth quarter 2014 production in the Bakken totaled 12,032 MBoe (130,783 Boe per day), an 8% increase over the third quarter of 2014 and 40% higher than the fourth quarter of 2013.

Production in SCOOP totaled 12,822 MBoe (35,128 Boe per day) for 2014, an 86% increase over 2013. SCOOP production totaled 3,717 MBoe (40,403 Boe per day) for the 2014 fourth quarter, an 11% increase over the third quarter of 2014 and 70% higher than the fourth quarter of 2013.

Property impairments

Significant decreases in crude oil prices in late 2014 adversely impacted the recoverability of capitalized costs in certain operating areas and contributed to the recognition of non-cash impairment charges totaling $394 million in the 2014 fourth quarter, bringing total impairments to $617 million for 2014, a 180% increase over 2013. The 2014 impairments were primarily concentrated in non-core areas of our North and South regions.

Derivative liquidations

In the fourth quarter of 2014, following a decrease in crude oil prices and related increase in the fair value of our derivative assets, substantially all of our crude oil derivative contracts were liquidated prior to the expiration of their contractual maturities. Our derivative liquidations occurred almost entirely in late October 2014 and resulted in the receipt of cash and recognition of pre-tax gains totaling approximately $433 million. The $433 million of proceeds included $85 million for contracts with original maturities in November and December of 2014, $337 million for contracts with original maturities in 2015, and $11 million for contracts with original maturities in 2016. As a result of the liquidations, our crude oil production and sales for 2015 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

Credit facility and liquidity

In May 2014, we entered into a new unsecured credit facility that provides for increased aggregate commitments and an extended maturity beyond the term of our previous credit facility. The new credit facility matures on May 16, 2019 and, when we entered into it, had aggregate commitments totaling $1.75 billion at December 31, 2014. The new credit facility replaced our previous $1.5 billion unsecured credit facility that was due to mature on July 1, 2015.

In February 2015, aggregate commitments on our credit facility were increased to $2.5 billion to provide additional liquidity if needed to maintain our growth strategy, take advantage of business opportunities, and fund our capital program and commitments. We had approximately $1.9 billion of borrowing availability on our credit facility at February 17, 2015 after considering outstanding borrowings and letters of credit.

Joint development agreement

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. Under the agreement, we sold a 49.9% interest in certain of our Northwest Cana properties. We received approximately $90 million in cash at closing and SK has committed to pay us an additional $270 million to fund, or carry, 50% of our remaining share of future drilling and completion costs over a period of approximately five years.

Issuance and redemption of senior notes

In May 2014, we issued $1.0 billion of 3.8% Senior Notes due 2024 and $700 million of 4.9% Senior Notes due 2044 and received total net proceeds of approximately $1.68 billion after deducting the initial purchasers' fees.

In July 2014, we redeemed our $300 million of 8.25% Senior Notes due 2019 for $317.5 million using proceeds from our May 2014 senior note issuances. We recognized a pre-tax loss of $24.5 million related to the redemption, which is reflected under the caption "Loss on extinguishment of debt" in our consolidated statements of comprehensive income for 2014.

Stock split

On August 18, 2014, our Board of Directors declared a 2-for-1 stock split of our common stock to be effected in the form of a stock dividend. The stock dividend was distributed on September 10, 2014 to shareholders of record as of September 3, 2014. All previously reported common stock and earnings per share amounts have been retroactively adjusted throughout this report to reflect the stock split.

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, 2014	2013	2012
Average daily production:			
Crude oil (Bbl per day)	121,999	95,859	68,497
Natural gas (Mcf per day)	313,137	240,355	174,521
Crude oil equivalents (Boe per day)	174,189	135,919	97,583
Average sales prices:			
Crude oil ($/Bbl)	$81.26	$89.93	$84.59
Natural gas ($/Mcf)	$5.40	$4.87	$3.73
Crude oil equivalents ($/Boe)	$66.53	$72.04	$65.99
Crude oil sales price differential to NYMEX ($/Bbl)	$(10.81)	$(8.23)	$(9.06)
Natural gas sales price premium to NYMEX ($/Mcf)	$1.02	$1.21	$0.93
Production expenses ($/Boe)	$5.58	$5.69	$5.49
Production taxes (% of oil and gas revenues)	8.2%	8.3%	8.3%
DD&A ($/Boe)	$21.51	$19.47	$19.44
General and administrative expenses ($/Boe)	$2.06	$2.11	$2.60
Non-cash equity compensation ($/Boe)	$0.86	$0.80	$0.82
Net income (in thousands)	$977,341	$764,219	$739,385
Diluted net income per share	$2.64	$2.07	$2.03
EBITDAX (in thousands) (1)	$3,776,051	$2,839,510	$1,963,123

(1)

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

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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	2014	2013	2012
Crude oil and natural gas sales	$4,203,022	$3,573,431	$2,349,500
Gain (loss) on derivative instruments, net (1)	559,759	(191,751)	154,016
Crude oil and natural gas service operations	38,837	40,127	39,071
Total revenues	4,801,618	3,421,807	2,542,587
Operating costs and expenses	(2,933,782)	(1,976,040)	(1,249,780)
Other expenses, net (2)	(305,798)	(232,718)	(137,611)
Income before income taxes	1,562,038	1,213,049	1,155,196
Provision for income taxes	(584,697)	(448,830)	(415,811)
Net income	$977,341	$764,219	$739,385
Production volumes:			
Crude oil (MBbl)	44,530	34,989	25,070
Natural gas (MMcf)	114,295	87,730	63,875
Crude oil equivalents (MBoe)	63,579	49,610	35,716
Sales volumes:			
Crude oil (MBbl)	44,122	34,985	24,958
Natural gas (MMcf)	114,295	87,730	63,875
Crude oil equivalents (MBoe)	63,172	49,607	35,604
Average sales prices:			
Crude oil ($/Bbl)	$81.26	$89.93	$84.59
Natural gas ($/Mcf)	$5.40	$4.87	$3.73
Crude oil equivalents ($/Boe)	$66.53	$72.04	$65.99

(1) The year 2014 includes $433 million of pre-tax gains recognized from crude oil derivative contracts that were settled in the fourth quarter 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, 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%

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	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 the SCOOP play 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 and Northwest Cana, due to natural declines in production. We expect natural gas production from our Northwest Cana properties will be positively impacted in 2015 by planned drilling activity associated with our joint development agreement with SK.

Revenues

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

Crude oil and natural gas sales. Crude oil and natural gas sales for 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 field and SCOOP play. 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 over the past year. Our properties in SCOOP produce a higher concentration of liquids-rich natural gas compared to certain other operating areas such as the Bakken.

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. 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 the year, 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 decrease in crude oil prices in the 2014 fourth quarter continued into early 2015 and we expect our crude oil sales prices for the 2015 first quarter will be lower than those realized in the 2014 fourth quarter. Crude oil prices remain volatile and we are unable to predict the impact future price changes may have on our full year 2015 crude oil revenues.

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. Crude oil price differentials have been volatile in recent months and years and we expect this volatility to continue.

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 reflects improved prices realized in connection with higher market prices for natural gas during the year. 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 ("NGLs") 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. NGL prices continued to decrease in early 2015 and we expect our sales prices for the 2015 first quarter will be lower than those realized in the 2014 fourth quarter. Natural gas and NGL prices remain volatile and we are unable to predict the impact future price changes may have on our full year 2015 natural gas revenues.

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. NGL market prices continued to trend lower in early 2015, which is expected to result in a further decline in our realized sales prices relative to Henry Hub benchmark pricing in 2015.

Derivatives. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the changes in fair value in the consolidated statements of comprehensive income under the caption “Gain (loss) on derivative instruments, net”, which is a component of total revenues.

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 the year, including the aforementioned $433 million of gains recognized on crude oil derivative liquidations in the 2014 fourth quarter. We expect our revenues will 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. However, future impacts on revenue may be less pronounced than those experienced in recent years given the liquidation of our crude oil derivative portfolio.

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. Production taxes are generally based on the wellhead values of production and vary by state. Some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana and Oklahoma, certain horizontal wells are taxed at a lower rate during their initial months of production which subsequently increases after a specified period of time or when specified production volumes are achieved.

North Dakota, our most active area, has a crude oil tax structure based on a 5% production tax and a 6.5% oil extraction tax for a combined tax of 11.5% of crude oil revenues. The 6.5% oil extraction tax has a series of built-in triggers that reduce or eliminate the tax depending on various commodity price and production circumstances. For instance, North Dakota law provides that if the average WTI oil price for a full calendar month falls below $57.50 per barrel, a reduced oil extraction tax rate of 2% becomes effective for wells having first production after the price trigger date. Additionally, if the average WTI oil price falls below a certain threshold ($55.09 per barrel for 2015) for five consecutive months, then the 6.5% oil extraction tax is reduced to 0% or 4% depending on the completion date and age of a well, which would impact a significant number of our wells in North Dakota. The reduced tax rates revert back to 6.5% under varying circumstances tied to WTI oil price increases, production and value limitations, and the passage of time.

For the month of January 2015, WTI oil prices, on average, were below the aforementioned $57.50 per barrel trigger price. Accordingly, our North Dakota wells having first production on or after February 1, 2015 will qualify for a reduced 2% oil extraction tax, subject to production, value and time limitations. Currently, we are unable to estimate the favorable impact this or any other potential tax rate reductions in North Dakota will have on our future operating results.

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	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 (“DD&A”). 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 over the prior year.

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 has 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 has 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. General and administrative (“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. Over the past year, our Company has grown from having 929 total employees in December 2013 to 1,188 total employees in December 2014, a 28% increase. Our personnel costs are not expected to increase in 2015 at the pace experienced in recent years given the impact on our 2015 business plans due to lower crude oil prices.

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.

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

Production

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

	Year Ended December 31,						Volume increase	Volume percent increase	
	2013			2012					
	Volume	Percent		Volume	Percent				
Crude oil (MBbl)	34,989	71	%	25,070	70	%	9,919	40	%
Natural Gas (MMcf)	87,730	29	%	63,875	30	%	23,855	37	%
Total (MBoe)	49,610	100	%	35,716	100	%	13,894	39	%

	Year Ended December 31,						Volume increase (decrease)		Percent increase (decrease)	
	2013			2012						
	MBoe	Percent		MBoe	Percent					
North Region	38,023	77	%	27,207	76	%	10,816		40	%
South Region	11,587	23	%	8,110	23	%	3,477		43	%
East Region (1)	—	—		399	1	%	(399	)	(100	%)
Total	49,610	100	%	35,716	100	%	13,894		39	%

(1) In December 2012, we sold the producing properties in our East region and no new wells have been subsequently drilled in that region. Accordingly, no production is reflected for the East region for 2013.

Crude oil production volumes increased 9,919 MBbls, or 40%, in 2013 compared to 2012. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in 2013 of 10,661 MBbls, a 57% increase over production in these areas for the same period in 2012. 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 418 MBbls associated with non-strategic properties in Wyoming and the East region that were sold in February 2012 and December 2012, respectively. Additionally, production from our properties in the Red River units and Northwest Cana play decreased a total of 308 MBbls, or 5%, over the prior year due to a combination of natural declines in production and reduced drilling activity in those areas.

Natural gas production volumes increased 23,855 MMcf, or 37%, in 2013 compared to 2012. Natural gas production in the Bakken field increased 11,299 MMcf, or 61%, in 2013 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 the SCOOP play increased 22,378 MMcf, or 317%, due to additional wells being completed and producing in 2013 compared to 2012. These increases were partially offset by decreases in production volumes totaling 9,554 MMcf, or 27%, from our properties in Northwest Cana, Arkoma Woodford, and non-core areas in our South region due to a combination of natural declines in production and reduced drilling activity. Additionally, natural gas production decreased 159 MMcf associated with non-strategic properties in Wyoming and the East region that were sold in February 2012 and December 2012, respectively.

Revenues

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

Crude oil and natural gas sales. Crude oil and natural gas sales for 2013 were $3.57 billion, a 52% increase from sales of $2.35 billion for 2012. Our sales volumes increased 14,003 MBoe, or 39%, over 2012 primarily due to the success of our drilling programs in the Bakken field and SCOOP play.

Our realized price per Boe increased $6.05 to $72.04 per Boe for 2013 from $65.99 per Boe for 2012. This increase reflected higher crude oil and natural gas prices realized in connection with improved market prices along with an improvement in crude oil differentials.

The differential between NYMEX WTI calendar month crude oil prices and our realized crude oil prices averaged $8.23 per barrel for 2013 compared to $9.06 for 2012. The improved differential reflected our efforts to shift Bakken crude oil sales to coastal markets in the United States having favorable pricing with less dependence on pipeline markets.

Derivatives. Changes in commodity prices during 2013 had an overall unfavorable impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $191.8 million for the year.

The following table presents the impact on total revenues related to cash settlements on matured derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented.

	Year ended December 31,	
In thousands	2013	2012
Cash received (paid) on derivatives:		
Crude oil derivatives	$(71,156)	$(55,579)

Natural gas derivatives	9,601	9,858
Cash paid on derivatives, net	(61,555)	(45,721)
Non-cash gain (loss) on derivatives:		
Crude oil derivatives	(126,167)	202,478
Natural gas derivatives	(4,029)	(2,741)
Non-cash gain (loss) on derivatives, net	(130,196)	199,737
Gain (loss) on derivative instruments, net	$(191,751)	$154,016

Operating Costs and Expenses
Production expenses. Production expenses increased 44% to $282.2 million for 2013 from $195.4 million for 2012. This increase was primarily the result of an increase in the number of producing wells along with higher costs incurred in 2013 from severe weather conditions encountered in the North region which created a more challenging operating environment compared to a mild winter season experienced in 2012. Production expense per Boe increased to $5.69 for 2013 compared to $5.49 per Boe for 2012.

Production taxes and other expenses. Production taxes and other expenses increased $100.3 million, or 51%, to $298.8 million for 2013 compared to $198.5 million for 2012 as a result of higher crude oil and natural gas revenues resulting from increased sales volumes and higher realized commodity prices. Production taxes as a percentage of crude oil and natural gas revenues were 8.3% for both 2013 and 2012.

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

	Year ended December 31,	
In thousands	2013	2012
Geological and geophysical costs	$25,597	$22,740
Exploratory dry hole costs	9,350	767
Exploration expenses	$34,947	$23,507

Geological and geophysical costs increased $2.9 million in 2013 due to changes in the timing and amount of acquisitions of exploratory seismic data between periods. Dry hole costs increased $8.6 million in 2013 and primarily reflected costs associated with exploratory wells in the Arkoma Woodford area and a non-Woodford area of our South region.

Depreciation, depletion, amortization and accretion. Total DD&A increased $273.5 million, or 40%, in 2013 compared to 2012 primarily due to a 39% 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	2013	2012
Crude oil and natural gas properties	$19.17	$19.10
Other equipment	0.24	0.25
Asset retirement obligation accretion	0.06	0.09
Depreciation, depletion, amortization and accretion	$19.47	$19.44

Property impairments. Property impairments increased in 2013 by $98.2 million to $220.5 million compared to $122.3 million in 2012.

Impairment provisions for proved properties were $51.8 million for 2013 compared to $4.3 million for 2012. The 2013 impairments primarily reflected fair value adjustments made for certain properties in the Niobrara play in Colorado and Wyoming driven by uneconomic well results. Impairment provisions for proved properties in 2012 reflected uneconomic operating results in a non-Woodford single-well field in our South region.

Impairments of non-producing properties increased $50.8 million in 2013 to $168.7 million compared to $117.9 million in 2012. The increase primarily resulted from a larger base of amortizable costs in 2013 coupled with higher rates of amortization resulting from changes in management's estimates of undeveloped properties not expected to be developed before lease expiration. Undeveloped leasehold costs on certain properties in the Niobrara play were assessed for impairment in the 2013 fourth quarter based on indicators of impairment and were written down to fair value, which resulted in impairment charges being recognized of $8.4 million.

General and administrative expenses. G&A expenses increased $22.7 million to $144.4 million for 2013 from $121.7 million for 2012. G&A expenses include non-cash charges for equity compensation of $39.9 million and $29.1 million for 2013 and 2012, respectively. The increase in equity compensation in 2013 resulted from a higher value of restricted stock grants being made throughout 2012 and 2013 due to employee growth, which resulted in increased expense recognition.

The relocation of our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma was completed during 2012; however, residual costs continued to be incurred into 2013 under the terms of our relocation plan offered to employees. For

2013, we recognized approximately $1.6 million of costs in G&A expenses associated with our relocation compared to $7.8 million in 2012. Cumulative relocation costs recognized through December 31, 2013 totaled approximately $12.6 million.

G&A expenses other than equity compensation and relocation expenses increased $18.1 million, or 21%, in 2013 compared to
2012. The increase was primarily due to an increase in personnel costs and office-related expenses associated with our employee growth. In 2013, our Company grew from having 753 total employees in December 2012 to 929 total employees in December 2013, a 23% increase.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented. The decrease in G&A expenses on a per-Boe basis in 2013 was due to the rapid growth in our crude oil and natural gas sales volumes coupled with an increase in G&A overhead costs billed to and recouped from our joint interest partners over the prior year, which helped generate lower costs realized per Boe.

	Year ended December 31,	
$/Boe	2013	2012
General and administrative expenses	$2.07	$2.38
Non-cash equity compensation	0.80	0.82
Corporate relocation expenses	0.04	0.22
Total general and administrative expenses	$2.91	$3.42

Interest expense. Interest expense increased $94.6 million to $235.3 million for 2013 from $140.7 million for 2012 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, 2013 was approximately $4.3 billion with a weighted average interest rate of 5.2% compared to averages of $2.3 billion and 5.6% for 2012. The increase in outstanding debt resulted from higher borrowings being incurred to fund our increased capital budget.

Income Taxes. We recorded income tax expense for 2013 of $448.8 million compared to $415.8 million for 2012, resulting in effective tax rates of approximately 37% and 36% for 2013 and 2012, respectively, after taking into account permanent taxable differences.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our credit facility and the issuance of debt and equity securities. At December 31, 2014, we had $24.4 million of cash and cash equivalents and approximately $1.6 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $165 million of outstanding borrowings on our credit facility at December 31, 2014, which subsequently increased to $605 million at February 17, 2015 as a result of additional 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.

In February 2015, the aggregate lender commitments on our credit facility were increased from $1.75 billion to $2.5 billion to provide additional liquidity if needed to maintain our growth strategy, take advantage of business opportunities, and fund our capital program and commitments. As of February 17, 2015, we had approximately $1.9 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. Based on our 2015 capital expenditure budget, our forecasted operating cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our credit facility and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to the various agreements subsequently described under the heading Contractual Obligations and in Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies, recognizing we may be required to meet such commitments even if our business plan assumptions were to change.

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Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $3.36 billion and $2.56 billion for the years ended December 31, 2014 and 2013, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues driven by higher sales volumes along with $433 million of proceeds received from crude oil derivative contracts that were settled in the fourth quarter of 2014 prior to their contractual maturities. These increases were partially offset by higher production expenses, production taxes, general and administrative expenses, interest expense and other expenses associated with the growth of our operations during the year.

If the depressed crude oil pricing environment existing in February 2015 persists or worsens, we expect our 2015 operating cash flows will be lower than 2014 levels.

Cash flows used in investing activities

During the years ended December 31, 2014 and 2013, we had cash flows used in investing activities (excluding proceeds from asset sales and other) of $4.72 billion and $3.74 billion, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $203.9 million and $268.1 million for the years ended December 31, 2014 and 2013, respectively. Cash capital expenditures excluding acquisitions totaled $4.51 billion and $3.47 billion for the years ended December 31, 2014 and 2013, respectively, the increase of which was driven by an increase in drilling activity in 2014.

The use of cash for capital expenditures during the year ended December 31, 2014 was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to $129.4 million for 2014, 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 our Northwest Cana properties in Oklahoma in September 2014.

For 2015, we currently expect our cash flows used in investing activities will be lower than 2014 levels due to our decision to reduce our planned drilling activity for 2015 in response to lower crude oil prices. Our capital expenditures for 2015 are budgeted to be $2.70 billion.

Cash flows from financing activities

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 issuances 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 $110.0 million on our credit facility and the July 2014 redemption of our 2019 Notes at a make-whole amount of $317.5 million.

Net cash provided by financing activities for the year ended December 31, 2013 totaled $1.14 billion, primarily resulting from the receipt of $1.48 billion of net proceeds from the issuance of $1.5 billion of 4.5% Senior Notes due 2023 in April 2013, partially offset by net repayments of $320.0 million on our credit facility.

Future Sources of Financing

Although we cannot provide any assurance, we believe funds from operating cash flows, our remaining cash balance and our credit facility, including our ability to increase our borrowing capacity thereunder, 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 the next 12 months. Our 2015 capital expenditures budget is reflective of the significant decrease in commodity prices in recent months and has been established based on an expectation of available cash flows from operations and availability under our credit facility. If operating 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 on our credit facility if needed to fund our operations. We may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

Based on our planned production growth, 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 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.

Credit facility

We have an unsecured credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $2.5 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 15 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. As of February 17, 2015, we had approximately $1.9 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. The commitments under our unsecured credit facility are not dependent on a borrowing base calculation subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, a downgrade or other negative rating action with respect to our credit rating will not trigger a reduction in our current credit facility commitments, nor will such action trigger a security requirement or change in covenants.

Our 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.

We were in compliance with our credit facility covenants at December 31, 2014 and expect to maintain compliance for at least the next 12 months. At December 31, 2014, our consolidated net debt to total capitalization ratio, as defined in the credit facility, was 0.55 to 1.00. We do not believe the restrictive covenants are reasonably likely to limit our ability to undertake additional debt or equity financing to a material extent. At December 31, 2014, our total debt would have needed to independently increase by approximately $3.25 billion, or 54%, 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 $1.75 billion, or 35%, below existing levels at December 31, 2014 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 net debt to 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 SK pursuant to which 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. The carry is expected to be realized over approximately the next five years. Refer to Part II, Item 8. Notes to Consolidated Financial Statements—Note 13. Property Acquisitions and Dispositions for further discussion.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $5.8 billion at December 31, 2014. 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 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, 2014 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 or equity financing. A downgrade or other negative rating action with respect to the credit ratings assigned to our senior unsecured debt does not trigger additional senior note covenants that are more restrictive than the existing covenants at December 31, 2014.

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. Our other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

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, 2014, we invested approximately $4.81 billion in our capital program, excluding $203.9 million of unbudgeted acquisitions and including $11.7 million of seismic costs and $290.8 million of capital costs associated with increased accruals for capital expenditures. Our capital expenditures budget for 2014 was $4.55 billion excluding unbudgeted acquisitions. Our 2014 capital expenditures were allocated as follows:

In millions	Amount
Exploration and development drilling	$4,322.4
Land costs	254.5
Capital facilities, workovers and other corporate assets	223.1
Seismic (1)	11.7
Capital expenditures, excluding acquisitions	$4,811.7
Acquisitions of producing properties	48.9
Acquisitions of non-producing properties	155.0
Total acquisitions	203.9
Total capital expenditures	$5,015.6

(1) Includes $8.0 million of exploratory seismic costs recognized as exploration expense and $3.7 million of developmental seismic costs capitalized in conjunction with development drilling projects.

Our 2014 capital program focused primarily on increased exploration and development in the Bakken field and SCOOP play.

In September 2014, our Board of Directors approved a 2015 capital expenditures budget of $5.20 billion excluding acquisitions, which was subsequently revised downward to $4.60 billion in November 2014 and again to $2.70 billion in December 2014 due to the significant decrease in crude oil prices in recent months. Our current 2015 budget of $2.70 billion is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$2,370
Land costs	180
Capital facilities, workovers and other corporate assets	138
Seismic	12
Total 2015 capital budget, excluding acquisitions	$2,700

Our 2015 capital plan is expected to focus on development drilling in the North Dakota Bakken and SCOOP plays, focusing on core areas of the plays that have the greatest potential to improve recoveries and rates of return.

Our 2015 capital expenditures budget has been established based on an expectation of available cash flows from operations and availability under our credit facility. 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. A decline in commodity prices could cause us to curtail our actual capital expenditures. 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, 2014:

	Payments due by period				
In thousands	Total	Less than 1 year (2015)	Years 2 and 3 (2016-2017)	Years 4 and 5 (2018-2019)	More than 5 years
Arising from arrangements on the balance sheet:					
Credit facility borrowings	$165,000	$ —	$—	$ 165,000	$—
Senior Notes (1)	5,800,000	—	—	—	5,800,000
Note payable (2)	16,457	2,078	4,358	4,646	5,375
Interest payments (3)	3,040,226	287,636	575,080	572,215	1,605,295
Asset retirement obligations (4)	76,708	1,246	1,220	404	73,838
Arising from arrangements not on balance sheet: (5)					
Operating leases and other (6)	24,601	10,714	6,771	3,648	3,468
Drilling rig commitments (7)	609,699	246,043	334,952	28,704	—
Fracturing and well stimulation services (8)	15,853	15,853	—	—	—
Pipeline transportation commitments (9)	969,306	182,018	368,897	315,470	102,921
Cost sharing commitment (10)	9,702	8,161	1,541	—	—
Fuel purchase commitment (11)	96,297	63,774	32,523	—	—
Total contractual obligations	$10,823,849	$ 817,523	$1,325,342	$ 1,090,087	$7,590,897

(1) Amounts represent scheduled maturities of our senior note obligations at December 31, 2014 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 term loan 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 credit facility borrowings outstanding at December 31, 2014 and assumes the actual weighted average interest rate on our credit facility borrowings of 2.5% at December 31, 2014 continues through the May 16, 2019 maturity date of the facility.

(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 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 through July 2018. These contracts were entered into in the ordinary course of business to ensure rig availability to allow us to execute our business objectives in our strategic plays.

(8) We have an agreement with a third party whereby the third party will provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of our properties in North Dakota and Montana. The agreement, which expires in September 2015, requires us to pay a fixed rate per day for a minimum number of days per calendar quarter over the term regardless of whether the services are provided.

(9) 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. In addition to the operational commitments reflected above, we are a party to a 5-year transportation commitment for a future crude oil pipeline project being considered for development that is not yet operational. Future commitments under the non-operational arrangement total approximately $260 million at December 31, 2014, which is not reflected above given that the timing of our obligations cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred

at all. 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.

(10) We have entered into an arrangement to share certain costs associated with a local utility company's construction and installation of electrical infrastructure that will provide service to parts of North Dakota where we operate. This arrangement extends through January 2016 and requires us to make scheduled periodic payments based on the projected total cost of the project and the progress of construction.

(11) We have entered into a forward purchase commitment with a third party to purchase specified quantities of diesel fuel at specified prices each month over the period from January 2015 through June 2016 for use in the normal course of our drilling operations. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies for additional discussion.

Under our joint development agreement with SK we have committed to drill within an area of mutual interest in our Northwest Cana properties over a period of approximately five years extending into 2019. Our share of the estimated future capital costs to be incurred under the agreement as of December 31, 2014 is approximately $270 million after SK’s 50% carry is applied to our 50.1% interest in the properties. These capital costs may not be incurred on a ratable basis over the term of the agreement. A portion of the expected costs is included in the drilling rig commitments caption in the table above.

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 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, 2014, 2013, and 2012, our proved reserves were revised upward (downward) from prior years' reports by approximately (107.9) MMBoe, (96.1) MMBoe, and 4.1 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, 2014, our proved reserves totaled 1,351 MMBoe as determined using 12-month average SEC prices. Holding all other factors constant, if commodity prices used in our year-end reserve estimates were decreased by $40.00 per barrel for crude oil and $1.00 per Mcf for natural gas, thereby approximating the pricing environment existing in February 2015, our proved reserves at December 31, 2014 could decrease by approximately 10%. If the proved reserves used in our DD&A calculations had been lower by 10% across all fields throughout 2014, our DD&A expense for 2014 would have increased by an estimated $145 million, or approximately 10%. 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 10% revision in reserves cannot be predicted with certainty and may result in a change that is greater or less than 10%.

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 crude oil and natural gas forward 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.
For producing properties, the 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. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and are subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Non-producing crude oil and natural gas properties, which consist primarily of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves, are assessed for impairment on a property-by-property basis for individually significant balances, if any, and on an aggregate basis by prospect for individually insignificant balances. The impairment assessment is 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. For individually insignificant non-producing properties, impairment losses 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 experience of successful drilling and the average holding period. The estimated 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, 2014, we believe all deferred tax assets, net of valuation allowances, recorded on 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.

Recent Accounting Pronouncements Not Yet Adopted

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606). The standard generally requires an entity to identify performance obligations in its contracts, estimate the amount of variable consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation, and recognize revenue as obligations are satisfied. The standard will be effective for annual and interim periods beginning after December 15, 2016. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. We are evaluating the impact of the provisions of ASU 2014-09; however, the standard is not expected to have a material effect on our financial position, results of operations or cash flows.

Additionally, we are monitoring the joint standard-setting efforts of the Financial Accounting Standards Board and International Accounting Standards Board. There are a number of pending accounting standards being targeted for completion in 2015 and beyond, including, but not limited to, standards relating to accounting for leases, fair value measurements, and financial instruments. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact these standards will have, if any, on our financial position, results of operations or cash flows.

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 we have 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, for 2015 certain service and equipment costs may decrease below 2014 levels as service providers reduce their costs in response to the significant decrease in crude oil prices in late 2014 and early 2015. Inflationary pressures may return in the future if crude oil 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 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 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	2014	2013	2012	2011	2010
Net income	$977,341	$764,219	$739,385	$429,072	$168,255
Interest expense	283,928	235,275	140,708	76,722	53,147
Provision for income taxes	584,697	448,830	415,811	258,373	90,212
Depreciation, depletion, amortization and accretion	1,358,669	965,645	692,118	390,899	243,601
Property impairments	616,888	220,508	122,274	108,458	64,951
Exploration expenses	50,067	34,947	23,507	27,920	12,763
Impact from derivative instruments:					
Total (gain) loss on derivatives, net	(559,759)	191,751	(154,016)	30,049	130,762
Total cash (paid) received on derivatives, net	385,350	(61,555)	(45,721)	(34,106)	35,495
Non-cash (gain) loss on derivatives, net	(174,409)	130,196	(199,737)	(4,057)	166,257
Non-cash equity compensation	54,353	39,890	29,057	16,572	11,691
Loss on extinguishment of debt	24,517	—	—	—	—
EBITDAX	$3,776,051	$2,839,510	$1,963,123	$1,303,959	$810,877

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	2014	2013	2012	2011	2010
Net cash provided by operating activities	$3,355,715	$2,563,295	$1,632,065	$1,067,915	$653,167
Current income tax provision	20	6,209	10,517	13,170	12,853
Interest expense	283,928	235,275	140,708	76,722	53,147
Exploration expenses, excluding dry hole costs	26,388	25,597	22,740	19,971	9,739
Gain on sale of assets, net	600	88	136,047	20,838	29,588
Excess tax benefit from stock-based compensation	—	—	15,618	—	5,230
Other, net	(17,279)	(1,829)	(7,587)	(4,606)	(3,513)
Changes in assets and liabilities	126,679	10,875	13,015	109,949	50,666
EBITDAX	$3,776,051	$2,839,510	$1,963,123	$1,303,959	$810,877

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, 2014, our PV-10 totaled approximately $22.77 billion. The Standardized Measure of our discounted future net cash flows was approximately $18.43 billion at December 31, 2014, representing a $4.34 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 pricing applicable to 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, 2014 and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $445 million for each $10.00 per barrel change in crude oil prices and $114 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 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. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements.

Changes in commodity prices during the year ended December 31, 2014 had an overall favorable impact on the fair value of our derivative instruments. For the year ended December 31, 2014, we recognized cash gains on derivatives of $385.4 million and reported a non-cash mark-to-market gain on derivatives of $174.4 million.

In the fourth quarter of 2014, following a decrease in crude oil commodity prices and related increase in the fair value of our derivative assets, substantially all of our crude oil derivative contracts were settled prior to the expiration of their contractual maturities, resulting in the receipt of cash proceeds totaling approximately $433 million. Consequently, our crude oil production and sales for 2015 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable. The only crude oil derivative arrangements that remain are certain written call options representing the ceiling positions from the Company's previous crude oil collar contracts that were not liquidated.

The fair value of our crude oil derivative instruments at December 31, 2014 was a net liability of $4.7 million. An assumed increase in the forward prices used in the year-end valuation of our crude oil derivatives of $10.00 per barrel would increase our crude oil derivative liability to approximately $10 million at December 31, 2014. Conversely, an assumed decrease in forward prices of $10.00 per barrel would decrease our crude oil derivative liability to approximately $2 million at December 31, 2014.

The fair value of our natural gas derivative instruments at December 31, 2014 was a net asset of $84.4 million. An assumed increase in the forward prices used in the year-end valuation of our natural gas derivatives of $1.00 per MMBtu would change our natural gas derivative valuation to a net liability of approximately $15 million at December 31, 2014. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative valuation to a net asset of approximately $191 million at December 31, 2014.

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, 2014.

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, refineries and affiliates ($566 million in receivables at December 31, 2014), our joint interest receivables ($568 million at December 31, 2014), and counterparty credit risk associated with our derivative instrument receivables ($84 million at December 31, 2014).

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 $116 million as of December 31, 2014, 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 credit facility. 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 $605 million of outstanding borrowings under our credit facility at February 17, 2015. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $6.1 million per year and a $3.8 million decrease in net income per year. Our credit facility matures on May 16, 2019 and the weighted-average interest rate on outstanding borrowings at February 17, 2015 was 1.8%.

The following table presents our debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2014:

In thousands	2015	2016	2017	2018	2019	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	$—	$—	$—	$—	$—	$5,800,000	$5,800,000
Weighted-average interest rate	—	—	—	—	—	4.9 %	4.9 %
Note payable:							
Principal amount	$2,078	$2,144	$2,214	$2,286	$2,360	$5,375	$16,457
Interest rate	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %
Variable rate debt:							
Credit facility:							
Principal amount	$—	$—	$—	$—	$165,000	$—	$165,000
Weighted-average interest rate	—	—	—	—	2.5 %	—	2.5 %

(1) Amount does 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 credit facility. 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 debt. A downgrade or other negative rating action with respect to our credit rating could increase our borrowing costs. 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, 2014 and 2013, and the related consolidated statements of comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, 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, 2015 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 24, 2015

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

In thousands, except par values and share data	December 31, 2014	2013
Assets		
Current assets:		
Cash and cash equivalents	$24,381	$28,482
Receivables:		
Crude oil and natural gas sales	552,476	643,498
Affiliated parties	13,360	13,107
Joint interest and other, net	567,476	349,579
Derivative assets	52,423	3,616
Inventories	102,179	54,440
Deferred and prepaid taxes	63,266	44,337
Prepaid expenses and other	14,040	10,207
Total current assets	1,389,601	1,147,266
Net property and equipment, based on successful efforts method of accounting	13,635,852	10,721,272
Net debt issuance costs and other	87,625	72,644
Noncurrent derivative assets	31,992	—
Total assets	$15,145,070	$11,941,182
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable trade	$1,263,724	$885,289
Revenues and royalties payable	272,755	291,772
Payables to affiliated parties	7,305	5,436
Accrued liabilities and other	404,506	198,113
Derivative liabilities	1,645	90,535
Current portion of long-term debt	2,078	2,011
Total current liabilities	1,952,013	1,473,156
Long-term debt, net of current portion	5,995,837	4,713,821
Other noncurrent liabilities:		
Deferred income tax liabilities	2,141,447	1,736,812
Asset retirement obligations, net of current portion	75,462	54,353
Noncurrent derivative liabilities	3,109	7,829
Other noncurrent liabilities	9,358	2,093
Total other noncurrent liabilities	2,229,376	1,801,087
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; 500,000,000 shares authorized; 372,005,502 shares issued and outstanding at December 31, 2014; 371,317,318 shares issued and outstanding at December 31, 2013	3,720	3,713
Additional paid-in capital	1,287,941	1,250,178
Accumulated other comprehensive loss	(385)	—
Retained earnings	3,676,568	2,699,227
Total shareholders’ equity	4,967,844	3,953,118
Total liabilities and shareholders’ equity	$15,145,070	$11,941,182

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

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

In thousands, except per share data	Year Ended December 31, 2014	2013	2012
Revenues:			
Crude oil and natural gas sales	$4,107,894	$3,473,026	$2,290,608
Crude oil and natural gas sales to affiliates	95,128	100,405	58,892
Gain (loss) on derivative instruments, net	559,759	(191,751)	154,016
Crude oil and natural gas service operations	38,837	40,127	39,071
Total revenues	4,801,618	3,421,807	2,542,587
Operating costs and expenses:			
Production expenses	347,349	280,789	193,466
Production and other expenses to affiliates	5,123	1,408	1,974
Production taxes and other expenses	349,760	298,787	198,505
Exploration expenses	50,067	34,947	23,507
Crude oil and natural gas service operations	21,871	29,665	32,248
Depreciation, depletion, amortization and accretion	1,358,669	965,645	692,118
Property impairments	616,888	220,508	122,274
General and administrative expenses	184,655	144,379	121,735
Gain on sale of assets, net	(600)	(88)	(136,047)
Total operating costs and expenses	2,933,782	1,976,040	1,249,780
Income from operations	1,867,836	1,445,767	1,292,807
Other income (expense):			
Interest expense	(283,928)	(235,275)	(140,708)
Loss on extinguishment of debt	(24,517)	—	—
Other	2,647	2,557	3,097
	(305,798)	(232,718)	(137,611)
Income before income taxes	1,562,038	1,213,049	1,155,196
Provision for income taxes	584,697	448,830	415,811
Net income	$977,341	$764,219	$739,385
Basic net income per share	$2.65	$2.08	$2.04
Diluted net income per share	$2.64	$2.07	$2.03
Comprehensive income:			
Net income	$977,341	$764,219	$739,385
Other comprehensive loss, net of tax			
Foreign currency translation adjustments	(385)	—	—
Total other comprehensive loss, net of tax	(385)	—	—
Comprehensive income	$976,956	$764,219	$739,385

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, 2011	361,743,376	$ 3,617	$ 1,108,885	$ —	$ 1,195,623	$ 2,308,125
Net income	—	—	—	—	739,385	739,385
Common stock issued in exchange for assets	7,832,314	78	81,450	—	—	81,528
Stock-based compensation	—	—	30,202	—	—	30,202
Excess tax benefit on stock-based compensation	—	—	15,618	—	—	15,618
Stock options:						
Exercised	173,000	2	58	—	—	60
Repurchased and canceled	(65,968)	—	(2,951)	—	—	(2,951)
Restricted stock:						
Granted	1,832,056	18	—	—	—	18
Repurchased and canceled	(225,042)	(2)	(8,283)	—	—	(8,285)
Forfeited	(80,374)	(1)	—	—	—	(1)
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

The accompanying notes are an integral part of these consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Year Ended December 31,		
In thousands	2014	2013	2012
Cash flows from operating activities:			
Net income	$977,341	$764,219	$739,385
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	1,368,311	965,437	694,698
Property impairments	616,888	220,508	122,274
Non-cash (gain) loss on derivatives, net	(174,409)	130,196	(199,737)
Stock-based compensation	54,353	39,890	29,057
Provision for deferred income taxes	584,677	442,621	405,294
Excess tax benefit from stock-based compensation	—	—	(15,618)
Dry hole costs	23,679	9,350	767
Gain on sale of assets, net	(600)	(88)	(136,047)
Loss on extinguishment of debt	24,517	—	—
Other, net	7,637	2,037	5,007
Changes in assets and liabilities:			
Accounts receivable	(129,634)	(166,138)	(91,791)
Inventories	(65,919)	(7,697)	(7,165)
Prepaid expenses and other	(57,489)	(11,537)	14,381
Accounts payable trade	85,540	107,250	(8,487)
Revenues and royalties payable	(18,022)	28,401	40,030
Accrued liabilities and other	58,880	44,260	40,309
Other noncurrent assets and liabilities	(35)	(5,414)	(292)
Net cash provided by operating activities	3,355,715	2,563,295	1,632,065
Cash flows from investing activities:			
Exploration and development	(4,604,468)	(3,660,773)	(3,493,652)
Purchase of producing crude oil and natural gas properties	(48,917)	(16,604)	(570,985)
Purchase of other property and equipment	(63,402)	(62,054)	(53,468)
Proceeds from sale of assets and other	129,388	28,420	214,735
Net cash used in investing activities	(4,587,399)	(3,711,011)	(3,903,370)
Cash flows from financing activities:			
Credit facility borrowings	1,695,000	970,000	2,119,000
Repayment of credit facility	(1,805,000)	(1,290,000)	(1,882,000)
Proceeds from issuance of Senior Notes	1,681,834	1,479,375	1,999,000
Redemption of Senior Notes	(300,000)	—	—
Premium on redemption of Senior Notes	(17,497)	—	—
Proceeds from other debt	—	—	22,000
Repayment of other debt	(2,013)	(1,951)	(1,579)
Debt issuance costs	(8,026)	(2,265)	(7,373)
Repurchase of equity grants	(16,583)	(14,690)	(11,236)
Excess tax benefit from stock-based compensation	—	—	15,618
Exercise of stock options	—	—	60
Net cash provided by financing activities	1,227,715	1,140,469	2,253,490
Effect of exchange rate changes on cash	(132)	—	—

Net change in cash and cash equivalents	(4,101)	(7,247)	(17,815)
Cash and cash equivalents at beginning of period	28,482	35,729	53,544
Cash and cash equivalents at end of period	$24,381	$28,482	$35,729

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 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 Kansas and all properties south of Kansas and west of the Mississippi River including various plays in the South Central Oklahoma Oil Province (“SCOOP”), Northwest Cana and Arkoma areas of Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River with no current drilling or production operations.

The Company’s operations are geographically concentrated in the North region, with that region comprising approximately 74% of the Company’s crude oil and natural gas production and approximately 83% of its crude oil and natural gas revenues for the year ended December 31, 2014. 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, 2014, approximately 69% of the Company’s estimated proved reserves were located in the North region. In 2012 and 2013, the Company significantly expanded its activity in the South region with its discovery and announcement of the SCOOP play in Oklahoma. The South region now comprises 26% of the Company's crude oil and natural gas production and 31% of its estimated proved reserves as of December 31, 2014.

The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the year ended December 31, 2014, crude oil accounted for approximately 70% of the Company’s total production and approximately 85% of its crude oil and natural gas revenues. Crude oil represents approximately 64% of the Company's estimated proved reserves as of December 31, 2014.

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.

Stock split

On August 18, 2014, the Company's Board of Directors declared a 2-for-1 stock split of the Company's common stock to be effected in the form of a stock dividend. The stock dividend was distributed on September 10, 2014 to shareholders of record as of September 3, 2014. All previously reported common stock and earnings per share amounts have been retroactively adjusted in the accompanying financial statements and related notes to reflect the stock split.

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. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with U.S. GAAP have been included in these consolidated financial statements.

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, 2014 and 2013 were not material.

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, 2014, the Company had cash deposits in excess of federally insured amounts of approximately $22.6 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, 2014, sales to the Company's two largest purchasers accounted for approximately 14% and 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 2014. 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 the Company's operating regions.

Inventories

Inventories are stated at the lower of cost or market and consist of the following:

	December 31,	
In thousands	2014	2013
Tubular goods and equipment	$15,659	$11,139
Crude oil	86,520	43,301
Total	$102,179	$54,440

Crude oil inventories are valued at the lower of cost or market using the first-in, first-out inventory method. Crude oil inventories consist of the following volumes:

	December 31,	
MBbls	2014	2013
Crude oil line fill and tank requirements	1,323	370
Temporarily stored crude oil	596	344
Total	1,919	714

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 resulted in an increase in crude oil stored in inventory at December 31, 2014 compared to December 31, 2013.

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 furniture and fixtures, automobiles, machinery and equipment, office equipment, computer equipment and software, 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
Furniture and fixtures	10
Automobiles	5-6
Machinery and equipment	10-20
Office equipment, computer equipment and software	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.

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, 2012 through December 31, 2014:

In thousands	2014	2013	2012
Asset retirement obligations at January 1	$55,787	$47,171	$62,625
Accretion expense	3,366	2,767	3,105
Revisions	9,916	2,826	(2,871)
Plus: Additions for new assets	9,022	6,009	6,679
Less: Plugging costs and sold assets (1)	(1,383)	(2,986)	(22,367)
Total asset retirement obligations at December 31	$76,708	$55,787	$47,171
Less: Current portion of asset retirement obligations at December 31 (2)	1,246	1,434	2,227
Non-current portion of asset retirement obligations at December 31	$75,462	$54,353	$44,944

(1) As a result of asset dispositions during the year ended December 31, 2012, the Company removed $20.0 million of its previously recognized asset retirement obligations that were assumed by the buyers. See Note 13. Property Acquisitions and Dispositions for further discussion.

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

As of December 31, 2014 and 2013, net property and equipment on the consolidated balance sheets included $64.7 million and $44.4 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, or when events and circumstances indicate a possible decline in the recoverability of the carrying value of such field. 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. Individually significant non-producing properties, if any, are assessed for impairment on a property-by-property basis and, if the assessment indicates an impairment, a loss is recognized by providing a valuation allowance consistent with the level at which impairment was assessed. For individually insignificant non-producing properties, impairment losses 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 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 credit facility and amendments thereto are capitalized and amortized over the term of the facility 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 $76.1 million and $69.5 million (net of accumulated amortization of $38.1 million and $28.8 million) relating to its long-term debt at December 31, 2014 and 2013, respectively. The increase in 2014 resulted from the capitalization of costs incurred in connection with the Company’s new credit facility and the May 2014 issuances of 3.8% Senior Notes due 2024 and 4.9% Senior Notes due 2044 as discussed in Note 7. Long-Term Debt. For the years ended December 31, 2014, 2013 and 2012, the Company recognized amortization expense associated with capitalized debt issuance costs of $9.3 million, $8.6 million and $5.6 million, respectively, which are reflected in “Interest expense” in the consolidated statements of comprehensive income.

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 anticipated 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 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, 2014 and 2013.

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. 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’s policy is to recognize penalties and interest related to unrecognized tax benefits, if any, in income tax expense.

Earnings per share

Basic net income per share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted net income per share reflects the potential dilution of non-vested restricted stock awards and stock options, 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 per share for the years ended December 31, 2014, 2013 and 2012. All stock options issued by the Company in prior periods had been exercised or had expired as of March 31, 2012. Weighted average shares and net income per share amounts for 2012 and 2013 have been retroactively adjusted to reflect the Company's 2-for-1 stock split occurring in September 2014.

	Year ended December 31,		
In thousands, except per share data	2014	2013	2012
Income (numerator):			
Net income - basic and diluted	$977,341	$764,219	$739,385
Weighted average shares (denominator):			
Weighted average shares - basic	368,829	368,150	362,680
Non-vested restricted stock	1,929	1,548	980
Stock options	—	—	32
Weighted average shares - diluted	370,758	369,698	363,692
Net income per share:			
Basic	$2.65	$2.08	$2.04
Diluted	$2.64	$2.07	$2.03

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 pronouncement

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers (Topic 606). The standard generally requires an entity to identify performance obligations in its contracts, estimate the amount of variable consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation, and recognize revenue as obligations are satisfied. The standard will be effective for annual and interim periods beginning after December 15, 2016. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company is evaluating the impact of the provisions of ASU 2014-09; however, the standard is not expected to have a material effect on the Company’s financial position, results of operations or cash flows.

Reclassifications

Prior to 2014, the Company presented charges related to natural gas transportation and processing under the caption “Production taxes and other expenses” or “Production and other expenses to affiliates” in the consolidated statements of comprehensive income. Effective January 1, 2014, such charges are netted within “Crude oil and natural gas sales” or "Crude oil and natural gas sales to affiliates", as applicable. Previously reported amounts have been reclassified to conform to the current year presentation. Reclassified amounts total $33.3 million and $29.9 million for the years ended December 31, 2013 and 2012, respectively, including transactions with an affiliate totaling $4.7 million for each of those respective years. The reclassifications had no impact on previously reported operating income, net income, current assets, total assets, current liabilities, total liabilities, stockholders' equity or cash flows.

Note 2. Supplemental Cash Flow Information

The following table discloses supplemental cash flow information about cash paid for interest and income taxes. 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	2014	2013	2012
Supplemental cash flow information:			
Cash paid for interest	$267,384	$209,815	$102,043
Cash paid for income taxes	53,457	29,017	829
Cash received for income tax refunds	7	174	13,866
Non-cash investing activities:			
Increase in accrued capital expenditures	290,782	89,482	49,039
Acquisition of assets through issuance of common stock (Note 11)	—	—	176,563
Asset retirement obligation additions and revisions, net	18,938	8,835	3,808

Note 3. Net Property and Equipment

Net property and equipment includes the following at December 31, 2014 and 2013:

	December 31,	
In thousands	2014	2013
Proved crude oil and natural gas properties	$17,045,967	$12,423,878
Unproved crude oil and natural gas properties	966,080	1,181,268
Service properties, equipment and other	274,584	236,233
Total property and equipment	18,286,631	13,841,379
Accumulated depreciation, depletion and amortization	(4,650,779)	(3,120,107)
Net property and equipment	$13,635,852	$10,721,272

Note 4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2014 and 2013:

	December 31,	
In thousands	2014	2013
Prepaid advances from joint interest owners	$115,687	$57,196
Accrued compensation	39,848	41,757
Accrued production taxes, ad valorem taxes and other non-income taxes	36,550	35,900
Deferred tax liabilities	145,349	—
Accrued interest	60,861	61,216
Current portion of asset retirement obligations	1,246	1,434
Other	4,965	610
Accrued liabilities and other	$404,506	$198,113

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 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 forecasted 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, the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price, and 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 NYMEX West Texas Intermediate ("WTI") pricing or 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.

In the fourth quarter of 2014, substantially all of the Company's outstanding crude oil derivative contracts were settled prior to the expiration of their contractual maturities scheduled through December 2016, resulting in the receipt of cash proceeds and recognition of gains totaling approximately $433 million which are included in the caption “Gain (loss) on derivative instruments, net" in the consolidated statements of comprehensive income for the year ended December 31, 2014. No natural gas derivative contracts in place were liquidated in the fourth quarter of 2014.

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At December 31, 2014, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil - NYMEX WTI		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price
July 2015 - December 2015			
Written call options - WTI (1)	2,208,000	$95.85 - $103.75	$98.36

Crude Oil - ICE Brent		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price
July 2015 - December 2015			
Written call options - ICE Brent (1)	368,000	$107.40	$107.40
January 2016 - December 2016			
Written call options - ICE Brent (1)	1,464,000	$107.70	$107.70

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 2015 - December 2015						
Swaps - Henry Hub	24,500,000	$4.27				
Collars - Henry Hub	29,200,000		$3.50 - $3.75	$3.69	$4.89 - $5.48	$5.04
January 2016 - December 2016						
Swaps - Henry Hub	63,110,000	$3.98				

(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 2014 fourth quarter. 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.

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	2014	2013	2012
Cash received (paid) on derivatives:			
Crude oil fixed price swaps (1)	$331,591	$(54,289)	$(40,238)
Crude oil collars (1)	65,310	(16,867)	(15,341)
Natural gas fixed price swaps	(11,551)	9,601	9,858
Cash received (paid) on derivatives, net	385,350	(61,555)	(45,721)
Non-cash gain (loss) on derivatives:			
Crude oil fixed price swaps	84,792	(117,580)	142,567
Crude oil collars	1,121	(8,587)	59,911
Crude oil written call options	3,981	—	—
Natural gas fixed price swaps	62,699	(4,029)	(2,741)
Natural gas collars	21,816	—	—
Non-cash gain (loss) on derivatives, net	174,409	(130,196)	199,737
Gain (loss) on derivative instruments, net	$559,759		