CONTINENTAL RESOURCES, INC
Form 10-K
February 27, 2014

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, 2013

or

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

For the transition period from to

Commission File Number: 001-32886

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

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

Registrant’s telephone number, including area code: (405) 234-9000

Securities registered pursuant to Section 12(b) of the Act:

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form

10-K. ¨

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2013 was approximately $4.9 billion, based upon the closing price of $86.06 per share as reported by the New York Stock Exchange on such date.

185,622,427 shares of our $0.01 par value common stock were outstanding on February 17, 2014.

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 2014, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Form 10-K.

Table of Contents

When we refer to "us," "we," "our," "Company," or "Continental" we are describing Continental Resources, Inc. and our subsidiaries.

Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section are 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.

"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.

"HPAI" High pressure air injection.

"hydraulic fracturing" A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production.
"in-field well" A well drilled between producing wells in a field to provide more efficient recovery of crude oil or natural gas from the reservoir.
"injection well" A well into which liquids or gases are injected in order to "push" additional crude oil or natural gas out of underground reservoirs and into the wellbores of producing wells. Typically considered an enhanced recovery process.
"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.
"microseismic" or "microseismic monitoring" Refers to the recording and imaging of seismic moments induced by hydraulic fracturing to provide technical data about fracture stimulation efficiency. This monitoring of fracture stimulations, being the industry's only measurement tool, yields technical data to allow for optimization of completion designs to help maximize production and/or reduce costs.
"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 revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and 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 multi-stage fracturing 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 emerging 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.
"3D (three dimensional seismic) defined locations" Locations that have been subjected to 3D seismic testing. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We do not typically evaluate reservoir productivity using 3D seismic technology.
"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.
"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.
"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.
"waterflood" The injection of water into a crude oil reservoir to "push" additional crude oil out of the reservoir rock and into the wellbores of producing wells. Typically an enhanced recovery process.
"wellbore" 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 includes “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. When used in this report, the words “could,” “may,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “budget,” “plan,” “continue,” “potential,” “g and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company’s current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes the expectations reflected in the forward-looking statements are reasonable and based on reasonable assumptions, no assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under Part I, Item 1A. Risk Factors included in this report, quarterly reports, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

Without limiting the generality of the foregoing, certain statements incorporated by reference, if any, or included in this report constitute forward-looking statements.

Forward-looking statements may include statements about:

- our business strategy;
- our future operations;
- our crude oil and natural gas reserves;
- our technology;
- our financial strategy;
- 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;
- plans, objectives, expectations and intentions contained in this report that are not historical, including, without limitation, statements regarding our future growth plans;
- 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.

We caution you these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for, and development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling, completion and production equipment and services and transportation infrastructure, environmental risks, drilling and other operating risks, lack of availability and security of computer-based systems, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under Part I, Item 1A. Risk Factors in this report, quarterly reports, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. 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. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements to reflect events or circumstances after the date of this report.

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,” “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.

We were originally formed in 1967 to explore for, develop and produce crude oil and natural gas properties. Through 1989, our activities and growth remained focused primarily in Oklahoma. In 1989, we expanded our activity into the North region. Our operations are now geographically concentrated in the North region, with that region comprising approximately 77% of our crude oil and natural gas production and approximately 86% of our crude oil and natural gas revenues for the year ended December 31, 2013. Approximately 76% of our estimated proved reserves as of December 31, 2013 are located in the North region.

We have focused our operations on the exploration and development of crude oil since the 1980s. For the year ended December 31, 2013, crude oil accounted for approximately 71% of our total production and approximately 87% of our crude oil and natural gas revenues. Crude oil represents approximately 68% of our estimated proved reserves as of December 31, 2013.

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, adding 1,046 MMBoe of proved crude oil and natural gas reserves through extensions and discoveries from January 1, 2009 through December 31, 2013 compared to 85 MMBoe added through proved reserve acquisitions during that same period. In October 2012, we announced a five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017.

As of December 31, 2013, our estimated proved reserves were 1,084.1 MMBoe, with estimated proved developed reserves of 406.8 MMBoe, or 38% of our total estimated proved reserves. For the year ended December 31, 2013, we generated crude oil and natural gas revenues of $3.6 billion and operating cash flows of $2.6 billion. For the year ended December 31, 2013, daily production averaged 135,919 Boe per day, a 39% increase over average production of 97,583 Boe per day for the year ended December 31, 2012. Average daily production for the quarter ended December 31, 2013 increased 35% to 144,254 Boe per day from 106,831 Boe per day for the quarter ended December 31, 2012.

The table below summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2013, average daily production for the quarter ended December 31, 2013 and the reserve-to-production index in our principal regions. 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 “Critical Accounting Policies and Estimates” in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations of this report for further discussion of uncertainties inherent to the reserve estimates.

Our reserve estimates as of December 31, 2013 are based primarily on a reserve report prepared by our independent reserve engineers, Ryder Scott Company, L.P (“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 94% of our proved natural gas reserves as of December 31, 2013. Our internal technical staff evaluated the remaining properties. Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2013 were determined using the 12-month unweighted arithmetic average of the first-day-of-the-month commodity prices for the period of January 2013 through December 2013, without giving effect to derivative transactions, and were held constant throughout the lives of the properties. These prices were

$96.78 per Bbl for crude oil and $3.67 per MMBtu for natural gas ($91.50 per Bbl for crude oil and $5.36 per Mcf for natural gas adjusted for location and quality differentials).

	December 31, 2013							
	Proved reserves (MBoe)	Percent of total		PV-10 (1) (In millions)	Net producing wells	Average daily production for fourth quarter 2013 (Boe per day)	Percent of total		Annualized reserve/production index (2)
North Region:									
Bakken field									
North Dakota Bakken	688,741	63.5	%	$ 13,093	779	80,374	55.7	%	23.5
Montana Bakken	52,401	4.8	%	1,437	233	12,961	9.0	%	11.1
Red River units									
Cedar Hills	54,191	5.0	%	1,522	130	10,498	7.3	%	14.1
Other Red River units	22,419	2.1	%	427	131	3,900	2.7	%	15.7
Other	1,884	0.2	%	32	16	812	0.6	%	6.4
South Region:									
SCOOP	214,667	19.8	%	3,286	74	23,754	16.5	%	24.8
Northwest Cana	29,827	2.8	%	198	73	6,696	4.6	%	12.2
Arkoma Woodford	11,103	1.0	%	69	59	2,769	1.9	%	11.0
Other	8,892	0.8	%	111	277	2,490	1.7	%	9.8
Total	1,084,125	100.0	%	$ 20,175	1,772	144,254	100.0	%	20.6

(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 $3.9 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 2013 production into estimated proved reserve volumes at December 31, 2013.

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The following table provides additional information regarding our key development areas as of December 31, 2013 and the budgeted amounts we plan to spend on exploratory and development drilling, capital workovers, and facilities in 2014.

	Developed acres		Undeveloped acres		2014 Plan Gross wells planned for drilling	Capital expenditures (1) (in millions)
	Gross	Net	Gross	Net		
North Region:						
Bakken field						
North Dakota Bakken	900,678	530,682	504,898	378,370	802	$2,233
Montana Bakken	159,943	135,426	214,358	165,343	68	413
Red River units	156,703	137,294	—	—	16	50
Niobrara - Colorado/Wyoming	12,087	8,529	126,662	69,526	—	—
Other	22,194	7,220	235,931	179,265	6	40
South Region:						
SCOOP	74,019	48,990	603,665	354,864	159	876
Northwest Cana	120,668	73,777	110,120	71,314	—	13
Arkoma Woodford	110,973	26,359	4,568	434	—	—
Other	100,710	46,008	197,434	167,506	9	65
East Region	—	—	152,762	144,363	—	—
Total	1,657,975	1,014,285	2,150,398	1,530,985	1,060	$3,690

(1) The capital expenditures budgeted for 2014 as reflected above include amounts for drilling, capital workovers and facilities and exclude budgeted amounts for land of $300 million, seismic of $30 million, and $30 million for vehicles, computers and other equipment. Potential acquisition expenditures are not budgeted.

Our Business Strategy

Our goal 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 our business strategy are:

Focus on crude oil. During the late 1980s we began to believe the 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, 2013, crude oil comprised 68% of our total proved reserves and 71% of our 2013 annual production.

Growth Through Drilling. A substantial portion of our annual capital expenditures are invested in drilling projects and acreage acquisitions. From January 1, 2009 through December 31, 2013, proved crude oil and natural gas reserve additions through extensions and discoveries were 1,046 MMBoe compared to 85 MMBoe of proved reserve acquisitions.

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, Bakken, and Oklahoma Woodford formations. The Oklahoma Woodford is a widespread unconventional shale reservoir that produces in various basins across the state of Oklahoma, with our properties being primarily concentrated in the SCOOP, Northwest Cana and Arkoma areas of the play. Production rates in the Red River units also have been sustained through the use of enhanced recovery technologies including water and high pressure air injection. Our production from the Red River units, the Bakken field, and the Oklahoma Woodford comprised approximately 48,324 MBoe, or 97%, of our total crude oil and natural gas production for the year ended December 31, 2013.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 970,325 net undeveloped acres held in the Bakken play in North Dakota and Montana and the Oklahoma Woodford, we held 560,660 net undeveloped acres in other crude oil and natural gas plays as of December 31, 2013. 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:

Large Acreage Inventory. We held 1,530,985 net undeveloped acres and 1,014,285 net developed acres as of December 31, 2013. Approximately 68% of the net undeveloped acres are located within unconventional resource plays in the Bakken (North Dakota and Montana), Woodford (Oklahoma) and the Niobrara (Colorado and Wyoming). The remaining balance of the net undeveloped acreage is located in conventional plays including 3D-defined locations for the Lodgepole (North Dakota), Morrow-Springer (Western Oklahoma) and Frio (South Texas) plays.

Experience with Horizontal Drilling and Enhanced Recovery Methods. We have substantial experience with horizontal drilling and enhanced recovery methods. In 1992, we drilled our first horizontal well, and we have drilled over 2,100 horizontal wells since that time. We continue to be a leader in the development of new drilling and completion technologies. Our trademarked ECO-Pad drilling concept, which allows for drilling multiple wells from a single pad, is becoming 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 a leader in extending lateral drilling lengths, in some instances up to three miles. In 2012, we completed the first multiple-unit spaced well drilled in Oklahoma, which had a horizontal section that was twice the length of previous laterals in the area. Longer laterals are believed to have a positive impact on well productivity and economics. Additionally, we are a leader in the exploration and evaluation of the lower layers or “benches” of the Three Forks formation in the Bakken field (referred to as the "Lower Three Forks"), initially targeting the first bench of the Three Forks in mid-2008 followed by the successful completion of our first well in the second bench in October 2011. In 2012, we successfully completed the first well ever drilled in the third bench of the Three Forks. In 2013, we completed our first of four pilot density projects in the Bakken and Three Forks formations, which included our first wells drilled in the fourth bench. The density project demonstrated the productive potential of multiple stacked zones and is helping us determine the optimum drilling and spacing pattern for future development of these reservoirs.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2013, we operated properties comprising 87% of our total proved reserves and 86% 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 fracture stimulation 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 30 years of crude oil and natural gas industry experience.

Strong Financial Position. In the second half of 2013, our corporate credit rating was upgraded to 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 most recently the SCOOP play. Our growth has been matched with a disciplined capital sourcing approach which has enabled a strong credit profile. We have a credit facility with lender commitments totaling $1.5 billion which may be increased up 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. We had $1.2 billion of available borrowing capacity under our credit facility at December 31, 2013 after considering outstanding borrowings and letters of credit. We believe our planned exploration and development activities will be funded substantially from our operating cash flows and credit facility borrowings. Our 2014 capital expenditures budget has been established based on our current expectation of available cash flows from operations and availability under our credit facility. Should expected available cash flows from operations materially differ from expectations, we believe our credit facility has sufficient availability to fund any deficit or that we can reduce our capital expenditures to be in line with cash flows from operations.

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, 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 tables set forth our estimated proved crude oil and natural gas reserves and PV-10 by reserve category as of December 31, 2013. The total Standardized Measure of discounted cash flows as of December 31, 2013 is also presented. Ryder Scott evaluated properties representing approximately 99% of our PV-10, 99% of our proved crude oil reserves, and 94% of our proved natural gas reserves as of December 31, 2013, and 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.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (1) (in millions)
Proved developed producing	277,845	761,729	404,800	$10,461.0
Proved developed non-producing	785	7,240	1,992	49.6
Proved undeveloped	459,158	1,309,051	677,333	9,664.8
Total proved reserves	737,788	2,078,020	1,084,125	$20,175.4
Standardized Measure (1)				$16,295.8

(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 $3.9 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, 2013.

	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	159,372	260,318	202,759	401,841	504,846	485,982
Montana Bakken	31,727	32,169	37,088	12,771	15,252	15,313
Red River units						
Cedar Hills	51,263	7,039	52,436	1,755	—	1,755
Other Red River units	17,472	13,400	19,705	2,714	—	2,714
Other	619	7,590	1,884	—	—	—
South Region:						
SCOOP	14,607	238,629	54,379	39,096	727,150	160,288
Northwest Cana	1,433	102,676	18,546	981	61,803	11,281
Arkoma Woodford	18	66,509	11,103	—	—	—
Other	2,119	40,639	8,892	—	—	—
Total	278,630	768,969	406,792	459,158	1,309,051	677,333

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

	Year Ended December 31,		
MBoe	2013	2012	2011
Proved reserves at beginning of year	784,677	508,438	364,712
Revisions of previous estimates	(96,054)	4,149	2,237
Extensions, discoveries and other additions	444,654	233,652	161,981
Production	(49,610)	(35,716)	(22,581)
Sales of minerals in place	—	(7,838)	—
Purchases of minerals in place	458	81,992	2,089
Proved reserves at end of year	1,084,125	784,677	508,438

Revisions of previous estimates. Revisions represent changes in previous reserve estimates, 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. Revisions for the year ended December 31, 2013 primarily represent the removal of proved undeveloped ("PUD") reserves resulting from a decision in 2013 to allocate a greater focus of our 5-year growth plan to our drilling programs in higher rates-of-return crude oil and liquids-rich natural gas areas of the Bakken and SCOOP while continuing to build on the early success in our development of the Lower Three Forks reservoirs in the Bakken. Another contributing factor is our increased focus 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 to maximize rates of return. These factors contributed to the removal of 81 MMBoe of PUD reserves in 2013.

Extensions, discoveries and other additions. These are additions to our proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields. Extensions, discoveries and other additions for each of the three years reflected in the table above were primarily due to increases in proved reserves associated with our successful drilling activity and strong production growth in the Bakken field. Proved reserve additions in the Bakken totaled 276 MMBoe for the year ended December 31, 2013. Additionally, 2013 extensions and discoveries were significantly impacted by successful drilling results in the emerging SCOOP play, resulting in 158 MMBoe of proved reserve additions during the year. Significant progress continued to be made in 2013 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 2013 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. During the year ended December 31, 2012, we disposed of certain non-strategic properties in Oklahoma, Wyoming, and our East region in an effort to redeploy capital to our strategic areas that we believe will deliver higher future growth potential. See Part II, Item 8. Notes to Consolidated Financial Statements—Note 13. Property Acquisitions and Dispositions for further discussion of our 2012 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 the year ended December 31, 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 and Note 14. Property Transaction with Related Party 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, 2013 totaled 677,333 MBoe, consisting of 459,158 MBbls of crude oil and 1,309,051 MMcf of natural gas. PUD reserves at December 31, 2013 were concentrated in the Bakken and SCOOP plays, our most active development areas, with those districts comprising 74% and 24%, respectively, of our total PUD reserves at year-end 2013. The following table provides information regarding changes in our PUD reserves for the year ended December 31, 2013.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved undeveloped reserves at December 31, 2012	334,293	795,585	466,891
Revisions of previous estimates	(52,440)	(251,475)	(94,354)
Extensions and discoveries	240,653	981,118	404,173
Purchases of minerals in place	23	26	28
Conversion to proved developed reserves	(63,371)	(216,203)	(99,405)
Proved undeveloped reserves at December 31, 2013	459,158	1,309,051	677,333

Revisions of previous estimates. During the year ended December 31, 2013, we removed 315 gross (174 net) PUD locations, which resulted in the removal of 42 MMBo and 235 Bcf (81 MMBoe) of PUD reserves. These removals were due to the aforementioned decision to allocate a greater focus of our 5-year growth plan to drilling programs in higher rates-of-return areas of the Bakken, SCOOP, and Lower Three Forks, with increased focus on areas capable of being developed via multi-well pad drilling. These factors contributed to the removal of PUD reserves in certain areas having less attractive rates of return or are otherwise less likely to be developed via pad drilling.

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 205 MMBo and 258 Bcf (248 MMBoe) in 2013, while SCOOP PUD reserve additions totaled 33 MMBo and 687 Bcf (147 MMBoe). See the subsequent section titled Summary of Crude Oil and Natural Gas Properties and Projects for a discussion of our 2013 drilling activities in the Bakken and SCOOP plays.

Conversion to proved developed reserves. In 2013, we developed approximately 21% of our PUD reserves and 20% of our PUD locations booked as of December 31, 2012 through the drilling of 360 gross (208 net) development wells at an aggregate capital cost of approximately $1.7 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. Development of our existing PUD reserves at December 31, 2013 is expected to occur within five years of the date of initial booking of the PUDs. Estimated future development costs relating to the development of PUD reserves are projected to be approximately $2.5 billion in 2014, $2.2 billion in 2015, $2.3 billion in 2016, $2.0 billion in 2017, and $1.0 billion in 2018. We expect our cash flows from operations and our credit facility will be sufficient to fund these future development costs. We had no PUD reserves at December 31, 2013 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 94% of our proved natural gas reserves as of December 31, 2013 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 Annual Report on 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 reserves 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 quarterly 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 29 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. 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, 2013:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	900,678	530,682	504,898	378,370	1,405,576	909,052
Montana Bakken	159,943	135,426	214,358	165,343	374,301	300,769
Red River units	156,703	137,294	—	—	156,703	137,294
Niobrara - Colorado/Wyoming	12,087	8,529	126,662	69,526	138,749	78,055
Other	22,194	7,220	235,931	179,265	258,125	186,485
South Region:						
SCOOP	74,019	48,990	603,665	354,864	677,684	403,854
Northwest Cana	120,668	73,777	110,120	71,314	230,788	145,091
Arkoma Woodford	110,973	26,359	4,568	434	115,541	26,793
Other	100,710	46,008	197,434	167,506	298,144	213,514
East Region	—	—	152,762	144,363	152,762	144,363
Total	1,657,975	1,014,285	2,150,398	1,530,985	3,808,373	2,545,270

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2013 that are expected 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.

	2014		2015		2016	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	126,232	84,679	143,555	118,609	107,462	107,257
Montana Bakken	63,762	51,399	65,541	46,973	38,375	36,632
Red River units	2,716	1,377	7,967	5,423	12,054	12,042
Niobrara - Colorado/Wyoming	13,574	8,800	83,531	45,692	23,538	10,816
Other	3,063	1,873	10,991	4,101	1,440	588
South Region:						
SCOOP	122,067	71,061	105,279	58,198	151,040	81,042
Northwest Cana	34,804	21,997	27,686	15,668	33,024	26,521
Arkoma Woodford	1,040	120	—	—	—	—
Other	1,202	733	85,919	64,276	15,932	16,767
East Region	9,657	7,486	14,187	9,760	5,128	4,695
Total	378,117	249,525	544,656	368,700	387,993	296,360

Drilling Activity

During the three years ended December 31, 2013, we drilled exploratory and development wells as set forth in the table below:

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Crude oil	75	51.5	76	37.0	50	23.4
Natural gas	40	23.7	78	43.8	109	45.9
Dry holes	3	2.1	1	1.0	2	1.3
Total exploratory wells	118	77.3	155	81.8	161	70.6
Development wells:						
Crude oil	734	250.9	561	211.3	380	126.1
Natural gas	26	5.4	5	2.4	17	1.6
Dry holes	—	—	3	1.1	5	0.6
Total development wells	760	256.3	569	214.8	402	128.3
Total wells	878	333.6	724	296.6	563	198.9

As of December 31, 2013, there were 404 gross (160.8 net) wells in the process of drilling, completing or waiting on completion.

As of February 17, 2014, we operated 43 rigs on our properties. Our rig activity during 2014 will depend on potential drilling efficiency gains and crude oil and natural gas prices and, accordingly, our rig count may increase or decrease from current levels. There can be no assurance, however, that additional rigs will be available to us at an attractive cost. See Part I, Item 1A. Risk Factors—The unavailability or high cost of additional 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

Throughout the following discussion, we discuss our budgeted number of wells and capital expenditures for 2014. Although we cannot provide any assurance, we believe our cash flows from operations, remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to satisfy our 2014 capital budget. 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. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flows, 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. Further, 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.

As referred to throughout this report, a “play” is a term applied to 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. “Conventional plays” are areas believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps. “Unconventional plays” are areas believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but generally require horizontal drilling, fracture stimulation treatments or other special recovery processes to achieve economic production. Unconventional plays 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. Our operations in unconventional plays include operations in the Bakken and Woodford plays and the Red River units. Our operations within conventional plays include operations in the Lodgepole of North Dakota, Morrow-Springer of western Oklahoma and Frio in south Texas. In general, unconventional plays require the application of more advanced technology and higher drilling and completion costs to produce relative to conventional plays. These technologies can include hydraulic fracturing treatments, horizontal wellbores, multilateral wellbores, or some other technique or combination of techniques to expose more of the reservoir to the wellbore.

References throughout this report to “3D seismic” refer to seismic surveys of areas by means of an instrument which records the travel time of vibrations sent through the earth and the interpretation thereof. By recording the time interval between the source of the shock wave and the reflected or refracted shock waves from various formations, geophysicists are better able to define the underground configurations. “3D defined locations” are those locations that have been subjected to 3D seismic testing. We typically use 3D seismic testing to evaluate reservoir presence and/or continuity. We do not typically evaluate reservoir productivity using 3D seismic technology.

North Region

Our properties in the North region represented 82% of our PV-10 as of December 31, 2013 and 75% of our average daily Boe production for the three months ended December 31, 2013. For the three months ended December 31, 2013, our average daily production from such properties was 108,545 Boe per day, an increase of 30% over our average daily production for the three months ended December 31, 2012. 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. Total production from the Bakken field reached a record 1.1 million barrels of oil equivalent ("MMBoe") per day in October 2013, up 39% over October 2012 based on data published by IHS Inc. and the North Dakota Industrial Commission. North Dakota remains the second largest oil producing state in the U.S. due to production growth in the Bakken field. As of December 31, 2013, there were 183 rigs actively drilling in the Bakken field.

We continue to be a leading producer, leasehold owner and driller in the Bakken field. Our Bakken field production averaged 93,335 Boe per day during the three months ended December 31, 2013, up 38% from our average daily Bakken field production for the three months ended December 31, 2012. Our properties within the Bakken field represented 72% of our PV-10 as of December 31, 2013 and 65% of our average daily Boe production for the three months ended December 31, 2013. Our total proved Bakken field reserves as of December 31, 2013 were 741 MMBoe, up 32% over our proved Bakken field reserves as of December 31, 2012. As of December 31, 2013, we controlled the largest leasehold position in the Bakken field with 1,779,877 gross (1,209,821 net) acres. Approximately 55% of our net acreage was developed and the remaining 45% was undeveloped as of December 31, 2013. As of December 31, 2013, we were the most active driller in the Bakken field, with 20 active operated rigs. As of December 31, 2013, we had completed 2,636 gross (1,025 net) wells in the Bakken field. Our inventory of proved undeveloped drilling locations in the Bakken field as of December 31, 2013 totaled 1,964 gross (1,119 net) wells.

We made significant progress with our development and exploration drilling programs in the Bakken field during 2013, completing a total of 749 gross (267 net) wells. We have reduced our drilling and completion costs on operated North Dakota Bakken wells from approximately $9.2 million in 2012 to approximately $8.0 million in 2013. The largest contributors to these cost reductions are multi-well pad development which reduced the overall footprint of our operations, advancements in stimulation and drilling technology, rig moving and location construction. We exited the year with over 70% of our rig activity on multi-well pads.

Of particular note was the success of our exploration program in the lower layers or "benches" of the Three Forks formation which demonstrated that wells completed in the Lower Three Forks reservoirs may be productive over an area at least 3,800 square miles in size, adding potential incremental recoverable reserves to the Bakken field. We also had success expanding the field extents onto our undeveloped leasehold through our step-out drilling program and we completed the first of four pilot density projects initiated during the year. These pilot density projects are designed to help us determine the optimum drilling and spacing pattern for future development of the Bakken and Three Forks reservoirs. We also initiated a pilot secondary recovery project to evaluate the potential for increasing the ultimate recovery of crude oil from the Bakken field through secondary injection methods. Progress of these pilot projects is ongoing.

We plan to invest approximately $2.5 billion drilling 870 gross (287 net) wells in the Bakken field during 2014, of which approximately 84% is expected to be invested in North Dakota and the remaining 16% in Montana. We plan to exit 2014 with 23 rigs drilling in the Bakken field with 19 rigs located in North Dakota and 4 rigs in Montana.

North Dakota Bakken

Our production and reserve growth in the Bakken field during 2013 came primarily from our activities in North Dakota. Production increased to an average rate of 80,374 Boe per day during the three months ended December 31, 2013, up 36% over the 2012 fourth quarter. Proved reserves increased 33% year-over-year to 689 MMBoe as of December 31, 2013. Our North Dakota Bakken properties represented 65% of our PV-10 at December 31, 2013 and 56% of our average daily Boe production for the three months ended December 31, 2013. In 2013, we completed 678 gross (211 net) wells, bringing our total number of wells drilled in North Dakota Bakken to 2,267 gross (788 net) wells as of December 31, 2013. As of December 31, 2013, we had 1,405,576 gross (909,052 net) acres in the North Dakota Bakken field, of which 58% of the net acreage is developed and the remaining 42% is undeveloped. Our inventory of proved undeveloped locations stood at 1,904 gross (1,074 net) wells as of December 31, 2013.

Our 2013 drilling activity in North Dakota focused on (1) developing our derisked areas, (2) expanding the field vertically and horizontally through step-out exploration drilling and (3) pilot density drilling to determine optimum well spacing and pattern for full field development. We successfully achieved our 2013 objectives in each of these areas and expect to continue making progress with these initiatives in 2014.

Our exploration drilling in North Dakota focused primarily on evaluating the productivity of the Lower Three Forks "benches" which include the Three Forks 2 ("TF2"), Three Forks 3 ("TF3"), and the Three Forks 4 ("TF4") reservoirs. These benches are layers of dolomite reservoir rock that underlie the proven producing Upper Three Forks bench known as the Three Forks 1 ("TF1"). Core work we completed over a year ago showed that these Lower Three Forks benches contained crude oil but it was unknown if they would produce crude oil at economic rates. During 2013, we successfully conducted a 24 well exploration drilling program to test these Lower Three Forks benches and completed 13 gross (9.5 net) wells in the TF2, 9 gross (7.2 net) wells in the TF3 and 2 gross (1.6 net) wells in the TF4. Results demonstrated that wells completed in the TF2 and TF3 are capable of producing crude oil at rates comparable to the TF1 across an area over 3,800 square miles in size. This discovery is significant as these results suggest the TF2 and TF3 reservoirs may add incremental recoverable reserves to the Bakken field. Results from the TF4 wells are being evaluated to determine their productive capabilities. At December 31, 2013, we have recorded approximately 20 MMBoe of proved reserves associated with the TF2 and TF3 benches in North Dakota Bakken.

To further assess the incremental reserve potential of the Lower Three Forks reservoirs and determine the optimum drilling density and pattern to maximize crude oil recovery from the Bakken field, we initiated four pilot density drilling projects during 2013. A total of 44 wells were drilled in these four projects during 2013. The first of the four pilot density projects to be completed and put into production was our Hawkinson unit. It was the first 1,280-acre unit that was fully developed on 320-acre spacing in the Bakken field and included four Middle Bakken wells, three TF1 wells, four TF2 wells and three TF3 wells. These 14 wells produced at a maximum combined initial 24 hour production rate of 14,850 barrels of oil equivalent per day. The Hawkinson density pilot employed several state of the art technologies including the largest downhole microseismic monitoring survey ever conducted in the world. All of this was done to help us determine the best inter-well spacing and pattern for future development of the Bakken field. We are currently monitoring production from the Hawkinson unit and incorporating the microseismic and technical data to assess performance. We also completed drilling operations on three additional pilot density projects in 2013 - the Tangsrud, Rollefstad, and Wahpeton projects - which we expect to begin producing during the first half of 2014. The Tangsrud and Rollefstad projects, like the Hawkinson project, are developing the Middle Bakken and first three benches of the Three Forks on 320-acre spacing while the Wahpeton project is developing the same zones on 160-acre spacing.

In 2014, we plan to invest approximately $2.1 billion drilling 802 gross (240 net) wells in the North Dakota Bakken. Approximately 13% of the capital expenditures will be spent on exploratory drilling which will include additional step-out drilling and three new pilot density projects. These new pilot density projects will further test the development of the Middle Bakken and first three benches of the Three Forks on 160-acre spacing. The remainder of the capital is expected to be spent drilling development wells in the field including our full field development program in the Antelope prospect in McKenzie and Williams Counties of North Dakota. This development drilling will be done using ECO-Pad technology. As of December 31, 2013, we had 16 operated rigs drilling in the North Dakota Bakken and plan to exit 2014 at 19 rigs.

Montana Bakken

Our Montana Bakken properties are located primarily within the Elm Coulee field in Richland County, Montana. Production from our Montana Bakken properties reached an all time high during the three months ended December 31, 2013, averaging 12,961 Boe per day over that period, up 52% from the average daily rate for the three months ended December 31, 2012. This reflects the success of our ongoing drilling program to optimize and expand our Montana Bakken properties. During 2013, we completed 71 gross (56 net) wells in Montana bringing our total number of wells drilled in Montana Bakken to 369 gross (237 net) wells as of December 31, 2013. As of December 31, 2013 our Montana Bakken properties represented 7% of our PV-10 and 9% of our average daily Boe production for the three months ended December 31, 2013. As of December 31, 2013, we had 374,301 gross (300,769 net) acres in Montana Bakken, of which 45% of the net acreage is developed and the remaining 55% is undeveloped. As of December 31, 2013, we had 60 gross (45 net) proved undeveloped locations identified in the Montana Bakken field.

In 2014, we plan to invest approximately $412 million drilling 68 gross (47 net) wells in the Montana Bakken. Our drilling will focus on additional infill development of Elm Coulee and continued expansion of the Elm Coulee field onto our undeveloped acreage north of the field. As of December 31, 2013, we had 4 rigs operating in the Montana Bakken and plan to exit 2014 with the same number of rigs.

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, a thin continuous, dolomite formation at depths of 8,000 to 9,500 feet. 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, which was listed by the U.S. Energy Information Administration in 2010 as the 9th largest onshore field in the lower 48 states of the United States ranked by 2009 proved liquid reserves.

All combined, our Red River units and adjacent areas represented 10% of our PV-10 as of December 31, 2013 and 10% of our average daily Boe production for the three months ended December 31, 2013. Our average daily production from these legacy properties decreased 2% in the fourth quarter of 2013 compared to the 2012 fourth quarter. The relatively shallow decline in these mature properties is due to optimization efforts and some limited drilling activity. Proved reserves were 77 MMBoe as of December 31, 2013. We are continuing to extend the performance life of our properties in the Red River units primarily by improving our water and air injection efficiency and taking other measures to optimize production. Additional enhanced recovery via carbon dioxide injection is currently being studied. As of December 31, 2013, we had 156,703 gross (137,294 net) acres in the Red River units and adjacent areas, all of which is developed acreage.

We have allocated $39 million of our 2014 capital expenditure budget to the Red River units and adjacent areas to support one drilling rig. Additional capital will be used to support injection projects and continued investment in facilities and infrastructure.

North Region Marketing Activities

Crude Oil. We continue to build upon a portfolio approach (rail and pipe) to marketing our crude oil that began in 2008 with our first shipments of crude oil by rail out of the Williston Basin. During 2013, we continued our efforts to shift Bakken crude oil sales to coastal markets in the United States with less dependence on currently available pipeline markets. Rail transportation costs are typically higher than pipeline transportation costs per barrel mile, but market prices realized in U.S. coastal markets continue to be competitive with currently available pipeline markets. We plan to continue pursuing this 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 fashion through the coming years, especially as we accelerate development drilling using ECO-Pad technology.

Natural Gas. Field infrastructure build-out continued in the Williston Basin in 2013 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 2013, we continued to make notable progress in adhering to our flaring reduction initiatives. For the year ended December 31, 2013, the percentage of our operated natural gas production flared in North Dakota Bakken was less than 11%, compared to 15% in 2012 and 19% in 2011. We expect to further reduce this amount as we continue to build out infrastructure and transition to a greater use of ECO-Pad development in 2014 and beyond.

South Region

Our properties in the South region represented 18% of our PV-10 as of December 31, 2013 and 25% of our average daily Boe production for the three months ended December 31, 2013. For the three months ended December 31, 2013, our average daily production from such properties was 35,709 Boe per day, up 58% from the same period in 2012. Our principal producing properties in this region are located in the emerging SCOOP play in south-central Oklahoma.

SCOOP

Our SCOOP properties are located in southern Oklahoma primarily in Garvin, Grady, Stephens, Carter, McClain and Love Counties. SCOOP represented 16% of our PV-10 as of December 31, 2013 and 17% of our average daily Boe production for the three months ended December 31, 2013. For the year ended December 31, 2013, SCOOP production grew 318% over 2012 due to our increased drilling activity in the play. For the three months ended December 31, 2013, SCOOP production averaged 23,754 Boe per day, up 233% over our average daily production for the three months ended December 31, 2012. As of December 31, 2013, we held 677,684 gross (403,854 net) acres under lease in SCOOP, of which 12% of the net acreage was developed and the remaining 88% of the net acreage was undeveloped. Our inventory of proved undeveloped drilling locations in SCOOP as of December 31, 2013 totaled 309 gross (153 net) wells.

We completed 77 gross (42 net) wells in SCOOP during 2013 and as of December 31, 2013 we had completed a total of 145 gross (79 net) wells in SCOOP. Our 2013 drilling program included exploration, step-out and development wells focused on de-risking the play and holding our acreage by production. The year 2013 was a particularly impactful year for SCOOP as our drilling results and results from others in the industry established both a crude oil and condensate rich, natural gas producing fairway that combined is approximately 20 miles wide and 120 miles long. Based on our 2013 drilling results, SCOOP is proving to be another significant asset for the Company with considerable potential for production and reserve growth.

A possible upside to SCOOP is the potential to encounter additional pay from a variety of conventional and potential unconventional reservoirs overlying and underlying the Woodford formation. There are over 60 different conventional reservoirs known to produce in the SCOOP area. These conventional reservoirs have the potential to produce locally under our SCOOP acreage.

In 2014, we plan to invest approximately $865 million to drill 159 gross (72 net) wells in the SCOOP play. Approximately 40% of these wells will be multi-unit wells. Multi-unit wells enable us to drill two spacing units from one location, which reduces well costs and our overall surface footprint. The 2014 drilling program will continue to focus on expanding the known productive extents of SCOOP and de-risking our acreage. It will also include pilot density projects to determine the optimum well spacing and pattern for full scale development of SCOOP in the future. We also expect to invest approximately $19 million to acquire approximately 230 square miles of additional proprietary 3D seismic data to guide future drilling. As of December 31, 2013, we had 18 operated rigs drilling in the SCOOP play.

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 anticipate continuing this approach through early 2015 and to begin delivery of 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 2013, 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.

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, 2013, 2012 and 2011 in total and for each field containing 15 percent or more of our total proved reserves as of December 31, 2013:

	Year ended December 31,		
	2013	2012	2011
Net production volumes:			
Crude oil (MBbls) (1)			
North Dakota Bakken	23,513	15,936	8,480
SCOOP	2,004	478	96
Total Company	34,989	25,070	16,469
Natural gas (MMcf)			
North Dakota Bakken	26,783	16,454	7,523
SCOOP	29,438	7,060	1,927
Total Company	87,730	63,875	36,671
Crude oil equivalents (MBoe)			
North Dakota Bakken	27,977	18,679	9,733
SCOOP	6,910	1,654	417
Total Company	49,610	35,716	22,581
Average sales prices: (2)			
Crude oil ($/Bbl)			
North Dakota Bakken	$89.45	$84.50	$88.43
SCOOP	95.63	89.37	93.02
Total Company	89.93	84.59	88.51
Natural gas ($/Mcf)			
North Dakota Bakken	$6.26	$5.55	$7.18
SCOOP	5.59	4.01	7.56
Total Company	5.25	4.20	5.24
Crude oil equivalents ($/Boe)			
North Dakota Bakken	$81.17	$76.95	$82.56
SCOOP	51.55	34.01	56.30
Total Company	72.71	66.83	73.05
Average costs per Boe: (2)			
Production expenses ($/Boe)			
North Dakota Bakken	$5.50	$4.31	$4.05
SCOOP	0.99	1.02	1.30
Total Company	5.69	5.49	6.13
Production taxes and other expenses ($/Boe)	$6.69	$6.42	$6.42
General and administrative expenses ($/Boe) (3)	$2.91	$3.42	$3.23
DD&A expense ($/Boe)	$19.47	$19.44	$17.33

(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 transportation constraints or we have sold crude oil from inventory. Crude oil sales volumes were 4 MBbls less than production volumes for the year

ended December 31, 2013,

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112 MBbls less than production volumes for the year ended December 31, 2012 and 30 MBbls less than production volumes for the year ended December 31, 2011.

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

(3) General and administrative expense ($/Boe) includes non-cash equity compensation expenses of $0.80 per Boe, $0.82 per Boe, and $0.73 per Boe for the years ended December 31, 2013, 2012 and 2011, respectively, and 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, respectively.

The following table sets forth information regarding our average daily production by region during the fourth quarter of 2013:

	Fourth Quarter 2013 Daily Production		
	Crude Oil (Bbls per day)	Natural Gas (Mcf per day)	Total (Boe per day)
North Region:			
Bakken field			
North Dakota Bakken	67,164	79,263	80,374
Montana Bakken	11,422	9,237	12,961
Red River units			
Cedar Hills	10,101	2,382	10,498
Other Red River units	3,468	2,592	3,900
Other	367	2,672	812
South Region:			
SCOOP	6,567	103,121	23,754
Northwest Cana	542	36,920	6,696
Arkoma Woodford	4	16,594	2,769
Other	808	10,085	2,490
Total	100,443	262,866	144,254

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, 2013:

	Crude Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
North Region:						
Bakken field						
North Dakota Bakken	2,261	778	6	1	2,267	779
Montana Bakken	361	232	2	1	363	233
Red River units						
Cedar Hills	136	130	—	—	136	130
Other Red River units	145	131	—	—	145	131
Other	33	15	4	1	37	16
South Region:						
SCOOP	45	23	96	51	141	74
Northwest Cana	11	6	157	67	168	73
Arkoma Woodford	3	—	397	59	400	59
Other	208	162	232	115	440	277
Total	3,203	1,477	894	295	4,097	1,772

As of December 31, 2013, we did not own interests in any wells containing multiple completions.

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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 any property, we procure a title opinion from external legal counsel and perform curative work necessary to satisfy requirements pertaining to material title defects. We generally will not commence drilling operations on a property until we have cured material title defects 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.

As a result of pipeline constraints, the continuous increase in Williston Basin production, and our desire to transport our crude oil to U.S. coastal markets which provide favorable pricing, in December 2013 we transported approximately 70% of our operated crude oil production from our North region by rail. We are using both manifest and unit train facilities for these shipments and anticipate these shipments will continue.

We have a strategic mix of gas transport, processing and sales arrangements for our natural gas production. Our natural gas production is sold at various points along the market chain from wellhead to 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.

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 years ended December 31, 2013, 2012 and 2011, sales to Marathon Crude Oil Company accounted for approximately 12%, 21% and 41% of our total crude oil and natural gas revenues, respectively. Sales to United Energy Trading accounted for approximately 11% of our total crude oil and natural gas revenues for both of the years ended December 31, 2013 and 2012. Additionally, sales to Tesoro Refining and Marketing Company accounted for approximately 15% of our total crude oil and natural gas revenues for the year ended December 31, 2013. No other purchasers accounted for more than 10% of our total crude oil and natural gas revenues for 2013, 2012 and 2011. We believe the loss of our largest 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

All of our operations are conducted onshore 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 pervasive and are continuously reviewed by legislators and regulators, including 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. Such requirements may have a significant effect on the exploration, development, production and sale of crude oil and natural gas. These requirements 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 our operations 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 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 our operations in a manner materially different than they would affect our similarly situated competitors.

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 does regulate the exportation of petroleum and petroleum products, and these regulations could restrict the markets for these commodities and thus affect sales prices. With regard to our physical sales of crude oil and 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 our operations in a way that materially differs from the effect on the operations of our competitors who are similarly situated.

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.

A portion of our North region crude oil production is shipped to market centers using rail transportation facilities owned and operated by third parties. 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 DOT, OSHA, 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 response to rail accidents occurring between 2002 and 2008, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. Recently, in response to train derailments occurring in the United States and Canada in 2013, U.S. regulators are implementing or considering new rules to address the safety risks of transporting crude oil by rail. On January 23, 2014, the National Transportation Safety Board ("NTSB") issued a series of recommendations to the FRA and PHMSA to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) to develop an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) to audit shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the U.S. Department of Transportation issued an emergency order requiring all persons, prior to offering petroleum crude oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of petroleum crude oil be handled as a Packing Group I or II hazardous material.

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 favorable prices 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. 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.

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 that will 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 other natural gas producers.

With regard to our physical sales of natural gas and derivative instruments relating to natural gas, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and the CFTC. See the discussion below of “Other Federal Laws and Regulations Affecting Our Industry—FTC and CFTC Market Manipulation Rules.” 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 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 our operations, 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 our operations in a way that materially differs from the effect on the operations of 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. 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 at which 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 competitors in the crude oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

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. This financial reform legislation includes provisions that require many derivative transactions that were then executed over-the-counter to be executed through an exchange and be centrally cleared. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to establish rules and regulations to implement the new legislation. The CFTC has issued final regulations to implement significant aspects of the legislation, including new rules for the registration of swap dealers and major swap participants (and related definitions of those terms), definitions of the term “swap,” rules to establish the ability to rely on the commercial end-user exception from the central clearing and exchange trading requirements, requirements for reporting and record keeping, rules on customer protection in the context of cleared swaps, and position limits for swaps and other transactions based on the price of certain reference contracts, some of which are referenced in our swap contracts. The position limits regulation has been vacated by a Federal court; however, the CFTC has proposed replacement rules. Key regulations that have not yet been finalized include those establishing margin requirements for uncleared swaps and regulatory capital requirements for swap dealers.

In December 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and certain index credit default swaps and setting compliance dates for different categories of market participants.

Mandatory clearing is now required for all such market participants, unless an exception is available, and certain interest rate swaps became subject to the trade execution requirements on February 15, 2014. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps, and the trade execution requirement does not apply to swaps that are not subject to a clearing mandate. Although we expect to qualify for the end-user exception from the clearing requirement for our swaps, mandatory clearing requirements and revised capital requirements applicable 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.

The CFTC's swap regulations may require or cause our counterparties to collect margin from us, and 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 new rules and any additional regulations on our business is uncertain. Of particular concern is whether our status as a commercial end-user will allow our derivative counterparties to not require us to post margin in connection with our commodity price risk management activities. The remaining final rules and regulations on major provisions of the legislation, such as new margin requirements, will be established through regulatory rule making.

In addition to the CFTC's swap regulations, other jurisdictions, including Canada, the European Union, Switzerland, Hong Kong, Singapore, Japan and Australia, 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 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 in this area, 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 planned to adopt the Dodd-Frank Act requirement that 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 plans to issue a revised proposal, the timing of which is uncertain.

The SEC has adopted the Dodd-Frank Act requirement that registrants disclose the use of conflict minerals in their products, and whether any of those minerals originated in certain conflict-ridden regions of Africa and financed or benefited armed groups. Certain business groups challenged the disclosure requirements; however, the requirements were upheld by a Federal court in a July 2013 ruling. The ruling has been appealed by the plaintiffs involved in the matter. We monitor our operations to determine if any disclosure or reporting obligations arise under the conflict mineral rules.

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. The anti-market manipulation rules and enhanced civil penalty authority reflect an expansion of the FERC's enforcement authority.

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 provided under 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 November 4, 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 and 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 that a court 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 of these or the above regulatory changes to our crude oil and natural gas operations. We do not believe we will be affected by any such action materially different than similarly situated competitors.

Environmental, health and safety regulation

General. Our operations 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 before drilling commences;
- 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; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

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. Continental is committed to conducting its operations in a manner that protects the health, safety and welfare of the public, its 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 risks and 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 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 continually train 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 any type of emergency affecting our personnel, facilities or the environment.

One current focus of our HSS&E initiatives is the reduction of air emissions produced from our operations, particularly with respect to flaring of 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. 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. 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.

In 2013, we continued to make notable progress in adhering to our flaring reduction initiatives. The percentage of our operated natural gas production flared in North Dakota Bakken, our most active area, was less than 11% in 2013, compared to 15% in 2012 and 19% in 2011. We believe this reduction is a notable accomplishment given the significant increase in our natural gas production in the Bakken field, including areas with less developed 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 North Dakota Industrial Commission ("NDIC"), our industry as a whole was flaring approximately 30% of produced natural gas volumes in the state as of late 2013. Since we are one of the largest producers in the North Dakota Bakken field, we believe the percentage of natural gas flared by the industry as a whole would be higher than 30% if Continental’s results were excluded from the NDIC’s data. Continental is a participant in the NDIC’s Flaring Reduction Task Force and is 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 Montana Bakken, we flared approximately 9% of the natural gas produced from our operated well sites in 2013. 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. We expect to further reduce flared natural gas volumes as we continue to build out transportation infrastructure and transition to a greater use of pad drilling in 2014 and beyond. 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 that 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 we are subject to 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 federal Occupational Safety and Health Act ("OSHA") and comparable state statutes, which require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations, and (xi) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material.

Climate change. Federal, state and local laws and regulations are increasingly 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.” Since its December 2009 endangerment finding regarding the emission of carbon dioxide, methane and other greenhouse gases, the EPA has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its “tailoring rule” in May 2010 that identifies which stationary sources of greenhouse gases are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gases. In November 2010, the EPA also finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires annual reporting to the EPA of greenhouse gas emissions by such regulated facilities.

In April 2012, the EPA issued final rules that established new air emission controls for crude oil and natural gas production and natural gas processing operations. These rules were published in the Federal Register on August 16, 2012. The EPA’s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with crude oil and natural gas production and processing activities. The final rules require the use of reduced emission completions or “green completions” on all hydraulically-fractured wells completed or refractured after January 1, 2015 in order to achieve a 95% reduction in the emission of VOCs. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules may require modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Moreover, in recent years the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Under past proposals, the EPA would issue or sell a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of such legislation, if adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states have adopted, or are in the process of adopting, similar cap-and-trade programs.

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. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies and migration of methane and other hydrocarbons. As a result, several federal agencies are studying the environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of “underground injection,” thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing and to require disclosure of the additives used in the process. If adopted, such legislation could establish an additional level of regulation and permitting at the federal level.

Scrutiny of hydraulic fracturing activities continues in other ways. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing environmental issues associated with hydraulic fracturing. The EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the draft results of which are anticipated to be available in 2014. Further, on May 11, 2012, the Bureau of Land Management ("BLM") issued a proposed rule 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. BLM published a supplemental notice of proposed rulemaking on May 24, 2013, which replaced the proposed rulemaking issued by the agency in May 2012. Additionally, on February 11, 2014 the EPA issued guidance governing the use of diesel fuel in hydraulic fracturing fluids. The guidance identifies five different variations of diesel and outlines new permitting guidelines for their use, along with technical recommendations for meeting the standards. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely. 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, the hydraulic fracturing process 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.

Employees

As of December 31, 2013, we employed 929 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 Ethics, please see our website. We intend to disclose amendments to, or waivers from, our Code of 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, before deciding to invest in shares of our common stock. 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 your shares 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 may adversely affect our business, financial condition or results of operations 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 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. Historically, the markets for crude oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide and regional economic conditions impacting the global supply and demand for crude oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign crude oil and natural gas;
- 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 level and effect of trading in commodity futures markets;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels or other energy sources.

Lower crude oil and natural gas prices could reduce our cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; limit our ability to borrow money or raise additional capital; and reduce the amount of crude oil and natural gas we can economically produce.
Substantial, extended decreases in crude oil and natural gas prices would render uneconomic a significant portion of our exploration, development and exploitation projects. This may result in significant downward adjustments to our estimated proved reserves. 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, liquidity or ability to finance planned capital expenditures.
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 77% of our crude oil and natural gas production and approximately 86% of our crude oil and natural gas revenues for the year ended December 31, 2013. Additionally, as of December 31, 2013 approximately 76% of our estimated proved reserves were located in the North region.
Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional events. These include, among others, fluctuations in 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, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. In addition, our operations in the North region may be adversely affected by seasonal weather and lease stipulations designed to protect wildlife, 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 exposure to unexpected events that may occur in this 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. Economic turmoil or uncertainty could reduce demand for crude oil and natural gas and put downward pressure on the prices of crude oil and natural gas. This would negatively impact our revenues, margins, profitability, operating cash flows, liquidity and financial condition. Such weakness or uncertainty could also cause our commodity hedging arrangements 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 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 increase our cost of financing. We have a credit facility with lender commitments totaling $1.5 billion. In the future, we may not be able to access adequate funding under our credit facility as a result of (i) a decrease in our credit ratings that triggers the reinstatement of a borrowing base requirement, subjecting us to the risk that other events may adversely impact the size of our borrowing base following reinstatement, (ii) a decline in commodity prices, or (iii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations or increase their commitments as required under the credit facility. Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required and 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, 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 and results of operations.

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 and production.

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 2013, we invested approximately $3.84 billion in our capital program, inclusive of property acquisitions. In October 2012, we announced a five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017. Our capital expenditures for 2014 are budgeted to be $4.05 billion, excluding acquisitions which are not budgeted, with $3.69 billion allocated for drilling, capital workovers and facilities. To date, our capital expenditures have been financed with cash generated by operations, borrowings under our credit facility and 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, commodity prices, available cash flows, 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. Improvement in commodity prices may result in an increase in actual capital expenditures. Conversely, a significant decline in commodity prices could result in a decrease in actual capital expenditures. 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 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 needs, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

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 banks to extend credit or the financial markets to accept offerings of our senior notes.

If revenues or our ability to borrow decrease as a result of lower crude oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing. 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 and results of operations and our ability to achieve our growth plan.

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:

- 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 hydraulic fracturing processes such as water and proppants;
- mechanical difficulties, fires, explosions, equipment failures or accidents, including ruptures of pipelines or train derailments;
- adverse weather conditions and natural disasters, such as flooding, blizzards and ice storms;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- reductions 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 third party service providers or us;
- limitations in infrastructure, including transportation capacity, or the market for crude oil and natural gas; and
- delays imposed by or resulting from compliance with regulatory requirements including permitting.

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.

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, 2013.

In order to prepare reserves estimates, we must project production rates and the amount and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. 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.

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.

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 cost and timing of development and production expenditures;
- the amount and timing of actual production;
- the actual prices we receive for sales of crude oil and natural gas; 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.

Actual future prices and costs may materially differ from those used in our estimate of the present value of future net revenues. If crude oil prices decline by $10.00 per barrel, our PV-10 as of December 31, 2013 would decrease approximately $2.8 billion. If natural gas prices decline by $1.00 per Mcf, our PV-10 as of December 31, 2013 would decrease approximately $1.3 billion.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to economically develop unconventional crude oil and natural gas resource plays using enhanced recovery technologies. For example, we may inject water and high-pressure air into formations on some of our properties to increase the production of crude oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If enhanced recovery programs do not allow for the extraction of crude oil and natural gas in the manner or to the extent we anticipate, our future results of operations and financial condition could be materially adversely affected.

If crude oil and natural gas prices decrease, we may be required to write down the carrying values of our crude oil and natural gas properties.

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 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 constitutes a non-cash charge to earnings. We may incur impairment charges in the future, 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 additional 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.
Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services, including key components used in hydraulic fracturing processes such as water and proppants, could delay 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 or results of operations.
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;
- natural disasters; and
- spillage or mishandling of crude oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third party service providers or us.

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 generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.
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

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 that 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 depends on 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 numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce crude oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. If we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 60% of our total net undeveloped acreage at December 31, 2013. At that date, we had leases representing 249,525 net acres expiring in 2014, 368,700 net acres expiring in 2015, and 296,360 net acres expiring in 2016. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

The marketability of our crude oil and natural gas production depends in part on the availability, proximity and capacity of pipeline and rail systems owned by third parties. The lack 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, material changes in these business relationships could materially affect our operations. Federal and state regulation of crude oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and rail systems, labor disputes and general economic conditions could adversely affect our ability to produce, gather, transport and sell crude oil and natural gas. We presently transport a significant portion of operated crude oil production from our North region to market centers by rail, with approximately 70% of such production being shipped by rail in December 2013.

The disruption of third-party pipelines or rail transportation facilities due to labor disputes, maintenance, civil disturbances, public protests, terrorist attacks, cyber attacks, adverse weather, regulatory developments, equipment failures or accidents, including pipeline ruptures or train derailments, could negatively impact our ability to market and deliver our products and achieve the most favorable prices for our crude oil and natural gas production. We have no control over when or if access to such pipeline or rail 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. See the subsequent risk factor titled Proposed legislation and regulation under consideration could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business for a discussion of regulations being introduced that could potentially impact the transportation of crude oil by rail.

Our business depends on the availability of water. Limitations or restrictions on our ability to obtain 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 could limit our ability to use techniques such as hydraulic fracturing. This could have a material adverse effect on our ability to economically find and develop crude oil and natural gas reserves.

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.
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 laws and regulations, including those governing environmental protection, health and safety, and the discharge of materials into the environment. 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.
Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders 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 and results of operations could be adversely affected. 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.
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 December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the Earth’s atmosphere and other climate changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of several regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act, such as the so-called “tailoring rule” adopted in May 2010, which imposes permitting and best available control technology requirements on the largest greenhouse gas stationary sources. In November 2010, the EPA also finalized its greenhouse gas reporting requirements for certain oil and gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires annual reporting to the EPA of greenhouse gas emissions by such regulated facilities.
In April 2012, the EPA issued final rules that established new air emission controls for crude oil and natural gas production and natural gas processing operations. These rules were published in the Federal Register in August 2012. The EPA’s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and VOCs and a separate set of emission standards to address hazardous air pollutants frequently associated with crude oil and natural gas production and processing activities. The final rules require the use of reduced emission completions or “green completions” on all hydraulically-fractured wells completed or refractured after January 1, 2015 in order to

achieve a 95% reduction in the emission of VOCs. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules may require modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of greenhouse gases, and almost half of the states, including states in which we operate, have enacted or passed measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs work by requiring either 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 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 and results of operations.

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 and 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.

A significant majority of our operations utilize hydraulic fracturing, 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. Some activists have attempted to link hydraulic fracturing to various environmental problems, including adverse effects to drinking water supplies as well as migration of methane and other hydrocarbons. As a result, several federal agencies are studying potential environmental risks with respect to hydraulic fracturing or evaluating whether to restrict its use. From time to time legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities from the definition of "underground injection," thereby requiring the crude oil and natural gas industry to obtain permits for hydraulic fracturing, and to require disclosure of the additives used in the process. If ever adopted, such legislation could establish an additional level of regulation and permitting at the federal level.

Scrutiny of hydraulic fracturing activities continues in other ways. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing environmental issues associated with hydraulic fracturing. The EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the draft results of which are anticipated to be available in 2014. Further, in May 2012, the BLM issued a proposed rule 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. BLM published a supplemental notice of proposed rulemaking on May 24, 2013, which replaced the proposed rulemaking issued by the agency in May 2012. Additionally, on February 11, 2014 the EPA issued guidance governing the use of diesel fuel in hydraulic fracturing fluids. The guidance identifies five different variations of diesel and outlines new permitting guidelines for their use, along with technical recommendations for meeting the standards. As of December 31, 2013, we held approximately 183,200 net undeveloped acres on federal land, representing approximately 12% of our total net undeveloped acres. In addition to these federal initiatives, several state and local governments, including states in which we operate, have moved to require disclosure of fracturing fluid components or to otherwise regulate their use more closely. 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. Such a circumstance would have a material adverse effect on our business and would impair our ability to implement our growth plan.

Should we fail to comply with FERC, FTC and CFTC administered statutes and regulations on market behavior, we could be subject to substantial penalties and fines and other liabilities.

The FERC, under the EPAct 2005, and the FTC, under the Energy Independence and Security Act of 2007, may impose or seek to impose through judicial action penalties for violations of anti-market manipulation rules for natural gas, crude oil and petroleum products of up to $1,000,000 per day for each violation. The CFTC, under the Commodity Exchange Act, has similar authority to assess penalties of up to the greater of $1,000,000 or triple the monetary gain for violation of anti-market manipulation rules for certain derivative contracts. Knowing or willful violations of the Commodity Exchange Act may also lead to a felony conviction. In addition, while we have not been regulated by the FERC as a natural gas company under the NGA, the FERC has adopted regulations that may subject us to the FERC annual reporting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC, the FTC or CFTC from time to time. Failure to comply with any of these regulations in the future could subject us to civil penalty liability, as well as the disgorgement of profits and third-party claims.

Proposed legislation and regulation 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, regulation 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 described below, 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 and results of operations.

We presently transport a significant portion of operated crude oil production from our North region to market centers by rail, with approximately 70% of such production being shipped by rail in December 2013. In response to recent train derailments occurring in the United States and Canada in 2013, U.S. regulators are implementing or considering new rules to address the safety risks of transporting crude oil by rail. On January 23, 2014, the NTSB issued a series of recommendations to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) to develop an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) to audit shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the U.S. Department of Transportation issued an emergency order requiring all persons, prior to offering petroleum crude oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of petroleum crude oil be handled as a Packing Group I or II hazardous material. The introduction of these or other regulations 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 favorable prices 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.

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 2014 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 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 2014 budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to crude oil and natural gas exploration and development, and any such change 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.

We 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 that were then 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 when enacted may require us to post collateral, which could adversely affect our available liquidity. If we reduce our use of derivatives 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 and results of operations.

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 and results of operations.

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, 2013, non-operated properties represented 19% of our estimated proved developed reserves, 10% of our estimated proved undeveloped reserves, and 13% of our estimated total proved reserves. We have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures required to fund such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. 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 materially adversely affect our financial condition and results of operations.

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 future goals.

Our credit facility and certain indentures for our senior notes include covenants and restrictions that may, among others, restrict:

- our investments, loans and advances and the paying of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the credit facility and certain permitted liens;
- mergers, consolidations and sales of all or a substantial part of our business or properties;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities; and
- the sale of assets.

Certain indentures for our outstanding senior notes may limit our ability and the ability of our restricted subsidiaries to:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends on stock, repurchase stock or redeem subordinated debt;
- make certain investments;
- enter into certain transactions with affiliates;
- create certain liens on our assets;
- sell or otherwise dispose of certain assets, including capital stock of subsidiaries;
- restrict dividends, loans or other asset transfers from our restricted subsidiaries;
- enter into new lines of business; and
- consolidate with or merge with or into, or sell all or substantially all of our properties to another person.

Our credit facility also requires us to maintain certain financial ratios, such as leverage ratios.

The restrictive covenants in our credit facility and the 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, such lenders or trustees could elect to declare 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 harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit ratings. 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, 2014, outstanding borrowings under our credit facility were $560 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 $5.6 million and a $3.5 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 ability to achieve our planned growth and operating results.

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 ($656.2 million in receivables at December 31, 2013), our joint interest receivables ($350.0 million at December 31, 2013), and counterparty credit risk associated with our derivative instrument receivables ($3.6 million at December 31, 2013). Joint interest receivables arise from billing entities who own a partial interest in the wells we operate. These 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 three largest purchasers of our crude oil and natural gas during the year ended December 31, 2013 accounted for a combined 38% of our total crude oil and natural gas revenues for the year. We generally do not require our counterparties to provide collateral to support 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 under the arrangements. 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 and results of operations.

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, we enter into derivative instruments for a portion of our crude oil and/or natural gas production, including collars and fixed price swaps. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Crude Oil and Natural Gas Hedging and 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 the prices for crude oil and natural gas. Our decision on the quantity and price at which we choose to hedge our future production 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. As part of our risk management program, we have hedged a significant portion of our forecasted production. We utilize a combination of derivative contracts based on West Texas Intermediate crude oil pricing, Inter-Continental Exchange pricing for Brent crude oil, and Henry Hub pricing for natural gas. We believe our derivative contracts provide relevant protection from price fluctuations in the U.S. markets where we deliver and sell our production. The pricing for Brent crude oil is believed to be a better reflection of the sales prices realized in certain U.S. market centers. However, in the event Brent prices increase significantly, the prices realized in those U.S. market centers may no longer be reflective of Brent prices. In such a circumstance, we may incur significant cash losses upon settling our crude oil derivative instruments. Such losses may be incurred without seeing a corresponding increase in revenues from higher realized prices on our physical sales of crude oil.

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, 2013, Harold G. Hamm, our Chairman and Chief Executive Officer, beneficially owned 126,337,891 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.

Several companies controlled by Mr. Hamm are 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, and expect to continue entering, into transactions from time to time with these 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:

- recoverable reserves;
- future crude oil and natural gas prices and their differentials;
- 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 of the subject properties we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities 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 often 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 the following ways, among others:

- unauthorized access to seismic data, reserves 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.

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Item 1B. Unresolved Staff Comments

There were no unresolved Securities and Exchange Commission staff comments at December 31, 2013.

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. 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. No cash dividends were declared during the previous two years.

	2013				2012			
	Quarter Ended				Quarter Ended			
	March 31	June 30	September 30	December 31	March 31	June 30	September 30	December 31
High	$93.99	$89.63	$108.19	$121.78	$97.19	$91.82	$84.19	$80.59
Low	$74.03	$72.35	$86.56	$100.25	$67.94	$61.50	$61.02	$66.07
Cash Dividend	—	—	—	—	—	—	—	—

Certain of our senior note indentures restrict the payment of dividends under certain circumstances and we do not anticipate paying any cash dividends on our common stock in the foreseeable future. As of February 17, 2014, the number of record holders of our common stock was 126. Management believes, after inquiry, that the number of beneficial owners of our common stock is approximately 57,200. On February 17, 2014, the last reported sales price of our common stock, as reported on the New York Stock Exchange, was $113.27 per share.

The following table summarizes our purchases of our common stock during the quarter ended December 31, 2013:

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, 2013 to October 31, 2013	—		—		—	—
November 1, 2013 to November 30, 2013	92,303	(1)	$116.45	(1)	—	—
December 1, 2013 to December 31, 2013	41,000	(2)	$102.20	(2)	—	—
Total	133,303		$112.07		—	—

(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. Effective May 23, 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. The 92,303 shares purchased above represent shares surrendered by employees to cover tax liabilities. The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares. We paid the associated taxes to the Internal Revenue Service.

(2) Represents shares of our common stock purchased by Harold G. Hamm, our Chairman, Chief Executive Officer, and controlling shareholder in an open-market transaction on December 11, 2013.

(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, 2013 relating to equity compensation plans:

	Number of Shares to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity Compensation Plans (1)
Equity Compensation Plans Approved by Shareholders	—	—	9,813,989
Equity Compensation Plans Not Approved by Shareholders	—	—	—

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

Performance Graph

The following graph compares our common stock performance with the performance of the Standard & Poor's 500 Stock Index ("S&P 500 Index") and the Dow Jones US Oil and Gas Index ("Dow Jones US O&G Index") for the period of December 2008 through December 2013. The graph assumes the value of the investment in our common stock and in each index was $100 on December 31, 2008 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 our selected consolidated financial data for the years ended December 31, 2009 through 2013. The selected financial data presented below is not intended to replace our consolidated financial statements.

The following consolidated financial data, as it relates to each of the fiscal years ended December 31, 2009 through 2013, has been derived from our audited consolidated financial statements for such periods. You should read the following selected consolidated 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,				
	2013	2012	2011	2010	2009
Income Statement data					
In thousands, except per share data					
Crude oil and natural gas sales	$3,606,774	$2,379,433	$1,647,419	$948,524	$610,698
Gain (loss) on derivative instruments, net (1)	(191,751)	154,016	(30,049)	(130,762)	(1,520)
Total revenues	3,455,150	2,572,520	1,649,789	839,065	626,211
Income from continuing operations	764,219	739,385	429,072	168,255	71,338
Net income	764,219	739,385	429,072	168,255	71,338
Basic earnings per share:					
From continuing operations	$4.15	$4.08	$2.42	$1.00	$0.42
Net income per share	$4.15	$4.08	$2.42	$1.00	$0.42
Shares used in basic earnings per share	184,075	181,340	177,590	168,985	168,559
Diluted earnings per share:					
From continuing operations	$4.13	$4.07	$2.41	$0.99	$0.42
Net income per share	$4.13	$4.07	$2.41	$0.99	$0.42
Shares used in diluted earnings per share	184,849	181,846	178,230	169,779	169,529
Production					
Crude oil (MBbl) (2)	34,989	25,070	16,469	11,820	10,022
Natural gas (MMcf)	87,730	63,875	36,671	23,943	21,606
Crude oil equivalents (MBoe)	49,610	35,716	22,581	15,811	13,623
Average sales prices (3)					
Crude oil ($/Bbl)	$89.93	$84.59	$88.51	$70.69	$54.44
Natural gas ($/Mcf)	5.25	4.20	5.24	4.49	3.22
Crude oil equivalents ($/Boe)	72.71	66.83	73.05	59.70	45.10
Average costs per Boe ($/Boe) (3)					
Production expenses	$5.69	$5.49	$6.13	$5.87	$6.89
Production taxes and other expenses	6.69	6.42	6.42	4.82	3.37
Depreciation, depletion, amortization and accretion	19.47	19.44	17.33	15.33	15.34
General and administrative expenses (4)	2.91	3.42	3.23	3.09	3.03
Proved reserves at December 31					
Crude oil (MBbl)	737,788	561,163	326,133	224,784	173,280
Natural gas (MMcf)	2,078,020	1,341,084	1,093,832	839,568	504,080
Crude oil equivalents (MBoe)	1,084,125	784,677	508,438	364,712	257,293
Other financial data (in thousands)					
Net cash provided by operating activities	$2,563,295	$1,632,065	$1,067,915	$653,167	$372,986
Net cash used in investing activities	(3,711,011)	(3,903,370)	(2,004,714)	(1,039,416)	(499,822)
Net cash provided by financing activities	1,140,469	2,253,490	982,427	379,943	135,829
EBITDAX (5)	2,839,510	1,963,123	1,303,959	810,877	450,648

Total capital expenditures	3,841,633	4,358,572	2,224,096	1,237,189	433,991
Balance Sheet data at December 31 (in thousands)					
Total assets	$11,941,182	$9,140,009	$5,646,086	$3,591,785	$2,314,927
Long-term debt, including current maturities	4,715,832	3,539,721	1,254,301	925,991	523,524
Shareholders' equity	3,953,118	3,163,699	2,308,126	1,208,155	1,030,279

(1) Derivative instruments are not designated as hedges for accounting purposes and, therefore, changes in the fair value of the instruments are shown separately from crude oil and natural gas sales. The amounts above include non-cash mark-to-market gains (losses) on derivative instruments of ($130.2) million, $199.7 million, $4.1 million, ($166.2) million and ($2.1) million for the years ended December 31, 2013, 2012, 2011, 2010, and 2009, respectively.

(2) At various times, we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil 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. For 2009, crude oil sales volumes were 82 MBbls less than crude oil production volumes.

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

(4) General and administrative expenses ($/Boe) include non-cash equity compensation expenses of $0.80 per Boe, $0.82 per Boe, $0.73 per Boe, $0.74 per Boe and $0.84 per Boe for the years ended December 31, 2013, 2012, 2011, 2010, and 2009, 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.

(5) EBITDAX represents 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, and non-cash equity compensation expense. 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 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. In December 2012, we sold the producing crude oil and natural gas properties in our East region. The sold properties represented an immaterial portion of our operations and do not materially affect the comparability of the operating results and cash flows for the periods presented in this report. Our operations are geographically concentrated in the North region, with that region comprising approximately 77% of our crude oil and natural gas production and approximately 86% of our crude oil and natural gas revenues for the year ended December 31, 2013.

We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. 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 provide the means to economically develop and produce crude oil and natural gas reserves from unconventional formations. We expect growth in our revenues and operating income will primarily depend on commodity prices and our ability to increase our reserves and related crude oil and natural gas production.

2013 Highlights

Proved reserves

At December 31, 2013, our estimated proved reserves totaled 1,084.1 MMBoe, an increase of 38% over proved reserves of 784.7 MMBoe at December 31, 2012. Extensions and discoveries resulting from our exploration and development activities were the primary drivers of our proved reserves growth in 2013, adding 444.7 MMBoe of proved reserves during the year. Our extensions and discoveries were primarily driven by successful drilling results and strong production growth in the Bakken field and the emerging SCOOP play. Our proved reserves in the Bakken field totaled 741.1 MMBoe at December 31, 2013, representing a 32% increase from 563.6 MMBoe at year-end 2012. Proved reserves in the SCOOP play increased 241% from 62.9 MMBoe at December 31, 2012 to 214.7 MMBoe at December 31, 2013. The year 2013 was an impactful year for SCOOP as our drilling results and results from others in the industry have helped establish a crude oil and liquids-rich natural gas productive fairway that has resulted in the booking of additional reserves from this emerging play.

Our properties in the Bakken field comprised 68% of our proved reserves at December 31, 2013, with SCOOP comprising 20% and the Red River units in North Dakota, South Dakota and Montana comprising 7%. The Bakken, SCOOP and Red River units comprised 72%, 8% and 10%, respectively, of our proved reserves at year-end 2012.

Estimated proved developed producing reserves were 404.8 MMBoe at December 31, 2013, representing 37% of our total estimated proved reserves compared with 39% at year-end 2012.

Crude oil reserves comprised 68%, or 737.8 MMBoe, of our estimated proved reserves at December 31, 2013 compared to 72% at December 31, 2012. The decreased percentage of crude oil reserves at December 31, 2013 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.
We seek to operate wells in which we own an interest. At December 31, 2013, we operated wells that accounted for 87% of our total proved reserves and 86% of our PV-10. By controlling operations, we are able to more effectively manage the costs and timing of exploration and development of our properties, including the drilling and completion methods used. Additionally, our business strategy has historically focused on reserve and production growth through exploration and development activities.

For the three-year period ended December 31, 2013, we added 840.3 MMBoe of proved reserves through extensions and discoveries, compared to 84.5 MMBoe added through acquisitions.

Production, revenues and operating cash flows

For the year ended December 31, 2013, our crude oil and natural gas production totaled 49,610 MBoe (135,919 Boe per day), representing a 39% increase from production of 35,716 MBoe (97,583 Boe per day) for the year ended December 31, 2012. Crude oil represented 71% of our 2013 production compared to 70% for 2012.

Our crude oil and natural gas production totaled 13,271 MBoe (144,254 Boe per day) for the fourth quarter of 2013, a 2% increase over production of 13,052 MBoe (141,873 Boe per day) for the third quarter of 2013 and a 35% increase over production of 9,829 MBoe (106,831 Boe per day) for the fourth quarter of 2012. Crude oil represented 70% of our production for the fourth quarter of 2013, 71% for the third quarter of 2013, and 72% for the fourth quarter of 2012.

The increase in 2013 production was primarily driven by higher production from our properties in the North Dakota Bakken field and the SCOOP play due to the continued success of our drilling programs in those areas.

Our Bakken production in North Dakota increased to 27,977 MBoe (76,649 Boe per day) for the year ended December 31, 2013, a 50% increase over the comparable 2012 period. Fourth quarter 2013 production in North Dakota Bakken totaled 7,394 MBoe (80,374 Boe per day), a 1% decrease from the third quarter of 2013 due to effects from adverse winter weather conditions and 36% higher than the fourth quarter of 2012.

Production in the emerging SCOOP play totaled 6,910 MBoe (18,932 Boe per day) for the year ended December 31, 2013, a 318% increase over the comparable 2012 period. SCOOP production totaled 2,185 MBoe (23,754 Boe per day) for the 2013 fourth quarter, an 18% increase over the third quarter of 2013 and a 233% increase over the fourth quarter of 2012.

Our crude oil and natural gas revenues for the year ended December 31, 2013 increased 52% to $3.61 billion due to a 39% increase in sales volumes and a 9% increase in realized commodity prices compared to the same period in 2012. Our realized price per Boe increased $5.88 to $72.71 per Boe for the year ended December 31, 2013 compared to 2012 due to higher commodity prices and improved crude oil differentials realized. Crude oil represented 87% of our total 2013 crude oil and natural gas revenues compared to 89% for 2012.

Crude oil and natural gas revenues totaled $912.3 million for the fourth quarter of 2013, a 36% increase over revenues of $670.4 million for the 2012 fourth quarter due to a 36% increase in sales volumes, with realized prices being consistent between periods. Crude oil represented 85% of our total crude oil and natural gas revenues for the fourth quarter of 2013 compared to 88% for the 2012 fourth quarter.

Our cash flows from operating activities for the year ended December 31, 2013 were $2.56 billion, a 57% increase from $1.63 billion provided by our operating activities during the comparable 2012 period. For the fourth quarter of 2013, operating cash flows totaled $584.8 million, 21% higher than operating cash flows of $484.2 million for the 2012 fourth quarter. The increased operating cash flows in 2013 were primarily due to higher crude oil and natural gas revenues resulting mainly from increased sales volumes, partially offset by an increase in cash losses on matured derivatives and higher production expenses, production taxes, general and administrative expenses, interest expense and other expenses associated with the growth of our operations over the past year.

Capital expenditures

Our capital expenditures budget for 2013 was $3.60 billion excluding acquisitions which are not budgeted. For the year ended December 31, 2013, we invested approximately $3.57 billion in our capital program (excluding $268.1 million of unbudgeted acquisitions and including $28.4 million of seismic costs and $89.5 million of capital costs associated with increased accruals for capital expenditures). Capital expenditures for the fourth quarter of 2013 totaled $867.5 million, excluding $71.2 million of unbudgeted acquisitions. Our 2013 capital program focused primarily on increased exploration and development in the Bakken field and SCOOP play.

Through leasing and acquisitions in 2013, we increased our Bakken acreage by 6% from 1,139,803 net acres at year-end 2012 to 1,209,821 net acres at year-end 2013 and increased our SCOOP acreage by 85% from 218,167 net acres at year-end 2012 to 403,854 net acres at year-end 2013.

Our capital expenditures budget for 2014 is $4.05 billion, excluding acquisitions. Our 2014 capital program is expected to continue focusing on exploratory and development drilling in the Bakken field and SCOOP play. We expect to continue participating as a buyer of properties if and when we have the ability to increase our position in strategic plays at competitive terms.

We economically hedge a portion of our anticipated future production to achieve more predictable cash flows and reduce our exposure to fluctuations in commodity prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. We expect our cash flows from operations, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to meet our budgeted capital expenditure needs for the next 12 months; however, 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.

Credit facility release of collateral

In November 2013, following an upgrade by Standard & Poor's Rating Services ("S&P"), as permitted by the credit facility terms, we provided the lenders under our credit facility notice of our intention to elect an Additional Covenant Period (as defined in the credit facility). The election of an Additional Covenant Period means that the credit facility is not currently subject to a borrowing base. The election was made in order to facilitate the release of collateral consisting of oil and gas properties securing obligations under the credit facility. On December 11, 2013, we delivered notice to the credit facility lenders confirming we had satisfied all conditions for releasing the collateral and the release of such collateral became effective as of December 12, 2013. On December 13, 2013 our credit rating was upgraded by Moody's Investor Services, Inc. ("Moody's"). As a result of the second upgrade, we are not currently required to: (i) comply with certain reporting requirements; and (ii) maintain a ratio of the present value of oil and gas properties to total funded debt of not less than 1.5 to 1.0, as set forth in the credit facility.

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.

	Year ended December 31,		
	2013	2012	2011
Average daily production:			
Crude oil (Bbl per day)	95,859	68,497	45,121
Natural gas (Mcf per day)	240,355	174,521	100,469
Crude oil equivalents (Boe per day)	135,919	97,583	61,865
Average sales prices: (1)			
Crude oil ($/Bbl)	$89.93	$84.59	$88.51
Natural gas ($/Mcf)	$5.25	$4.20	$5.24
Crude oil equivalents ($/Boe)	$72.71	$66.83	$73.05
Production expenses ($/Boe) (1)	$5.69	$5.49	$6.13
Production taxes (% of oil and gas revenues)	8.2 %	8.2 %	7.9 %
DD&A ($/Boe) (1)	$19.47	$19.44	$17.33
General and administrative expenses ($/Boe) (1)	$2.91	$3.42	$3.23
Net income (in thousands)	$764,219	$739,385	$429,072
Diluted net income per share	$4.13	$4.07	$2.41
EBITDAX (in thousands) (2)	$2,839,510	$1,963,123	$1,303,959

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

(2) EBITDAX represents 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, and non-cash equity compensation expense. 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	2013	2012	2011
Crude oil and natural gas sales	$3,606,774	$2,379,433	$1,647,419
Gain (loss) on derivative instruments, net (1)	(191,751)	154,016	(30,049)
Crude oil and natural gas service operations	40,127	39,071	32,419
Total revenues	3,455,150	2,572,520	1,649,789
Operating costs and expenses (2)	(2,009,383)	(1,279,713)	(889,037)
Other expenses, net	(232,718)	(137,611)	(73,307)
Income before income taxes	1,213,049	1,155,196	687,445
Provision for income taxes	(448,830)	(415,811)	(258,373)
Net income	$764,219	$739,385	$429,072
Production volumes:			
Crude oil (MBbl) (3)	34,989	25,070	16,469
Natural gas (MMcf)	87,730	63,875	36,671
Crude oil equivalents (MBoe)	49,610	35,716	22,581
Sales volumes:			
Crude oil (MBbl) (3)	34,985	24,958	16,439
Natural gas (MMcf)	87,730	63,875	36,671
Crude oil equivalents (MBoe)	49,607	35,604	22,551
Average sales prices: (4)			
Crude oil ($/Bbl)	$89.93	$84.59	$88.51
Natural gas ($/Mcf)	5.25	4.20	5.24
Crude oil equivalents ($/Boe)	72.71	66.83	73.05

(1) Amounts include a non-cash mark-to-market loss on derivative instruments of $130.2 million for the year ended December 31, 2013 and non-cash mark-to-market gains on derivative instruments of $199.7 million and $4.1 million for the years ended December 31, 2012 and 2011, respectively.

(2) Amounts are net of gains on sales of assets of $0.1 million, $136.0 million, and $20.8 million for the years ended December 31, 2013, 2012 and 2011, respectively. See Notes to Consolidated Financial Statements—Note 13. Property Acquisitions and Dispositions for further discussion of 2011 and 2012 dispositions.

(3) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between produced and sold crude oil volumes. Crude oil sales volumes were 4 MBbls less than crude oil production for the year ended December 31, 2013, 112 MBbls less than crude oil production for the year ended December 31, 2012 and 30 MBbls less than crude oil production for the year ended December 31, 2011.

(4) Average sales prices have been calculated using sales volumes and exclude any effect of derivative transactions.

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, 2013 MBoe	Percent	2012 MBoe	Percent	Volume increase (decrease)	Percent increase (decrease)
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 crude oil and natural gas 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 the year ended December 31, 2013.

Crude oil production volumes increased 9,919 MBbls, or 40%, for the year ended December 31, 2013 compared to the year ended December 31, 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 is 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%, for the year ended December 31, 2013 compared to the same period in 2012. Natural gas production in the Bakken field increased 11,299 MMcf, or 61%, for the year ended December 31, 2013 compared to the same period in 2012 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 the year ended December 31, 2013 were $3.61 billion, a 52% increase from sales of $2.38 billion for the same period in 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 $5.88 to $72.71 per Boe for the year ended December 31, 2013 from $66.83 per Boe for the year ended December 31, 2012. This increase reflects 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 West Texas Intermediate ("WTI") calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2013 was $8.23 compared to $9.06 for the year ended December 31, 2012. The improved differential reflects our continued efforts to shift Bakken crude oil sales to coastal markets in the United States with less dependence on currently available pipeline markets. We continue to employ a portfolio approach (rail and pipe) in transporting to multiple U.S. coastal and inland markets and expect this trend to continue in 2014. Rail transportation costs are typically higher than pipeline transportation costs per barrel mile, but market prices realized in U.S. coastal markets continue to be competitive with currently available pipeline markets. We plan to continue pursuing this portfolio approach to balance volumes delivered to pipeline and rail market destinations in an effort to maximize net wellhead value.

While our crude oil differentials in 2013 generally improved over levels experienced in 2012, they widened in recent months as Bakken production in the Williston basin continued to grow and seasonal refinery maintenance and outages resulted in a temporary reduction in demand for Bakken crude oil. As a result, our realized crude oil differential to WTI averaged $13.05 per barrel in the fourth quarter of 2013 compared to $7.80 per barrel for the 2013 third quarter and $3.21 per barrel for the 2012 fourth quarter. The wide differentials realized in the 2013 fourth quarter are expected to continue into the first quarter of 2014. We expect crude oil differentials to ultimately improve from current levels but for volatility to continue.

Derivatives. We have entered into a number of derivative contracts, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and drilling program. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. 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 income under the caption "Gain (loss) on derivative instruments, net", which is a component of total revenues.

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

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

	Year ended December 31,			
In thousands	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	

The non-cash mark-to-market gains and losses reflected above for the year ended December 31, 2013 relate to derivative instruments with various terms that are scheduled to mature over the period from January 2014 to December 2015. Over this period, actual derivative settlements may differ significantly, either positively or negatively, from the mark-to-market valuation at December 31, 2013.

Operating Costs and Expenses

Production expenses and production taxes and other expenses. Production expenses increased 44% to $282.2 million for the year ended December 31, 2013 from $195.4 million for the year ended December 31, 2012. This increase is 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 the year ended December 31, 2013 compared to $5.49 per Boe for the year ended December 31, 2012.

Production taxes and other expenses increased $103.7 million, or 45%, to $332.1 million for the year ended December 31, 2013 compared to $228.4 million for the year ended December 31, 2012 as a result of higher crude oil and natural gas revenues resulting from increased sales volumes and higher realized commodity prices. Production taxes and other expenses in the consolidated statements of income include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $33.3 million and $29.9 million for the years ended December 31, 2013 and 2012, respectively. The increase in other charges is primarily due to higher natural gas sales volumes in 2013. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.2% for both years ended December 31, 2013 and 2012. 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, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate reverts to the statutory rate.

On a unit of sales basis, production expenses and production taxes and other expenses were as follows:

	Year ended December 31,	
$/Boe	2013	2012
Production expenses	$5.69	$5.49
Production taxes and other expenses	6.69	6.42
Production expenses, production taxes and other expenses	$12.38	$11.91

Production expenses averaged $6.03 per Boe for the fourth quarter of 2013. The increase in the fourth quarter was due to higher costs incurred resulting from severe winter weather in the North region that created a challenging operating environment. The increased costs, coupled with delayed completions and reduced production from curtailed wells in North Dakota during that time, resulted in higher per-unit production expenses for the quarter.

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 indicated.

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

Exploratory geological and geophysical costs increased $2.9 million for the year ended December 31, 2013 due to changes in the timing and amount of acquisitions of exploratory seismic data between periods. Dry hole costs increased $8.6 million for the year ended December 31, 2013 and primarily reflect costs associated with exploratory wells in the Arkoma Woodford area and a non-Woodford area of our South region.

Depreciation, depletion, amortization and accretion (“DD&A”). Total DD&A increased $273.5 million, or 40%, for the year ended December 31, 2013 compared to the year ended December 31, 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

DD&A for crude oil and natural gas properties averaged $20.08 per Boe for the fourth quarter of 2013. Fourth quarter DD&A was impacted by the operational timing of pad drilling and resulting mix of well completions during the year.

Property impairments. Property impairments increased in the year ended December 31, 2013 by $98.2 million to $220.5 million compared to $122.3 million for the year ended December 31, 2012.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. Individually significant non-producing properties, if any, are assessed for impairment on a property-by-property basis. Impairments of non-producing properties increased $50.8 million for the year ended December 31, 2013 to $168.7 million compared to $117.9 million for the year ended December 31, 2012. The increase primarily resulted from a larger base of amortizable costs in the current year coupled with higher rates of amortization resulting from changes in management’s estimates of undeveloped properties not expected to be developed before lease expiration. Additionally, undeveloped leasehold costs on certain properties in the Niobrara play were individually 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.

Impairment provisions for proved properties were $51.8 million for the year ended December 31, 2013 compared to $4.3 million for the same period in 2012. We evaluate proved crude oil and natural gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then

we impair it based on an estimate of fair value based on discounted cash flows. Impairments of proved properties in 2013 primarily reflect 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 reflect uneconomic operating results in a non-Woodford single-well field in our South region.

General and administrative expenses. General and administrative ("G&A") expenses increased $22.7 million to $144.4 million for the year ended December 31, 2013 from $121.7 million for the comparable period in 2012. G&A expenses include non-cash charges for equity compensation of $39.9 million and $29.1 million for the years ended December 31, 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 in 2013 compared to the prior year.

The previously announced 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 the year ended December 31, 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 rapid growth. Over the past year, our Company has grown 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 the year ended December 31, 2013 from $140.7 million for the comparable period in 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 a weighted average outstanding long-term debt balance of approximately $2.3 billion and a weighted average interest rate of 5.6% for the comparable period in 2012. The increase in outstanding debt resulted from the issuances of 5% Senior Notes due 2022 in 2012 and 4 1/2% Senior Notes due 2023 in 2013, the net proceeds of which were used to repay credit facility borrowings, to fund a portion of our capital budgets and for general corporate purposes.

Our weighted average outstanding credit facility balance decreased to $281.9 million for the year ended December 31, 2013 compared to $322.1 million for the year ended December 31, 2012. The weighted average interest rate on our credit facility borrowings was 2.0% for the year ended December 31, 2013 compared to 2.3% for the same period in 2012. At December 31, 2013, we had $275 million of outstanding borrowings on our credit facility compared to $595 million outstanding at December 31, 2012.

Income Taxes. We recorded income tax expense for the year ended December 31, 2013 of $448.8 million compared to $415.8 million for the year ended December 31, 2012, resulting in effective tax rates of approximately 37% and 36% for 2013 and 2012, respectively, after taking into account permanent taxable differences.

Year ended December 31, 2012 compared to the year ended December 31, 2011

Production

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

	Year Ended December 31, 2012 Volume	2012 Percent	2011 Volume	2011 Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	25,070	70 %	16,469	73 %	8,601	52 %
Natural Gas (MMcf)	63,875	30 %	36,671	27 %	27,204	74 %
Total (MBoe)	35,716	100 %	22,581	100 %	13,135	58 %

	Year Ended December 31, 2012 MBoe	2012 Percent	2011 MBoe	2011 Percent	Volume increase (decrease)	Percent increase (decrease)
North Region	27,207	76 %	17,462	77 %	9,745	56 %
South Region	8,110	23 %	4,705	21 %	3,405	72 %
East Region (1)	399	1 %	414	2 %	(15)	(4 %)
Total	35,716	100 %	22,581	100 %	13,135	58 %

(1) In December 2012, we sold the producing crude oil and natural gas properties in our East region to a third party for $126.4 million. See Notes to Consolidated Financial Statements—Note 13. Property Acquisitions and Dispositions for further discussion of the transaction.

Crude oil production volumes increased 52% during the year ended December 31, 2012 compared to the year ended December 31, 2011. Production increases in the Bakken field, the Northwest Cana play and SCOOP play contributed incremental production volumes in 2012 of 8,493 MBbls, an 81% increase over production in these areas for the same period in 2011. Production growth in these areas was primarily due to increased drilling and completion activity resulting from our drilling program. Additionally, production in the Red River units increased 177 MBbls, or 4%, in 2012 due to new wells being completed and enhanced recovery techniques being successfully applied.

Natural gas production volumes increased 27,204 MMcf, or 74%, during the year ended December 31, 2012 compared to the same period in 2011. Natural gas production in the Bakken field increased 9,414 MMcf, or 104%, for the year ended December 31, 2012 compared to the same period in 2011 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 Northwest Cana and SCOOP plays in Oklahoma increased 17,839 MMcf, or 156%, due to additional wells being completed and producing in the year ended December 31, 2012 compared to the same period in 2011. Further, natural gas production increased 716 MMcf, or 81%, in non-Bakken areas in the North region compared to 2011 due to the completion of new wells during the period. These increases were partially offset by a decrease in production volumes of 837 MMcf, or 6%, from non-core areas in our South region due to a combination of natural declines in production and reduced drilling activity prompted by the pricing environment for natural gas in those areas.

Revenues

Crude oil and natural gas sales. Crude oil and natural gas sales for the year ended December 31, 2012 were $2.38 billion, a 44% increase from sales of $1.65 billion for the same period in 2011. Our sales volumes increased 13,053 MBoe, or 58%, over 2011 due to the success of our drilling programs in the North Dakota Bakken field and Northwest Cana play, along with early success achieved in the emerging SCOOP play in Oklahoma. Our realized price per Boe decreased $6.22 to $66.83 for the year ended December 31, 2012 from $73.05 for the year ended December 31, 2011 due to lower commodity prices and higher crude oil differentials realized.

The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for the year ended December 31, 2012 was $9.06 compared to $6.39 for the year ended December 31, 2011. Overall increased production and constrained logistical factors had a negative effect on our realized crude oil prices during 2012 and resulted in higher differentials compared to 2011. Factors contributing to the changing differential included a continued increase in crude oil production across the Williston Basin from the Bakken play as well as increased production and imports from Canada.

Additionally, pipeline transportation capacity remained constrained in the Williston Basin throughout 2012 and it was not until the latter part of the year that improved rail transportation takeaway capacity began to have a positive effect on differentials. Positive effects of stronger sales pricing in coastal U.S. markets began to be realized in the fourth quarter of 2012 despite high costs being incurred for rail transportation. As a result, our crude oil differentials to NYMEX improved late in the year and averaged $3.21 per barrel for the 2012 fourth quarter.

Derivatives. Changes in commodity prices during 2012 had an overall positive net impact on the fair value of our derivatives, which resulted in net positive revenue adjustments of $154.0 million for the year. 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 crude oil and natural gas prices. 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	2012	2011
Cash received (paid) on derivatives:		
Crude oil derivatives	$(55,579)	$(71,411)
Natural gas derivatives	9,858	37,305
Cash paid on derivatives, net	(45,721)	(34,106)
Non-cash gain (loss) on derivatives		
Crude oil derivatives	202,478	18,753
Natural gas derivatives	(2,741)	(14,696)
Non-cash gain on derivatives, net	199,737	4,057
Gain (loss) on derivative instruments, net	$154,016	$(30,049)

Operating Costs and Expenses

Production expenses and production taxes and other expenses. Production expenses increased 41% to $195.4 million for the year ended December 31, 2012 from $138.2 million for the year ended December 31, 2011. This increase was primarily the result of an increase in the number of producing wells. Production expense per Boe decreased to $5.49 for the year ended December 31, 2012 compared to $6.13 per Boe for the year ended December 31, 2011. This decrease was due in part to higher costs being incurred in the prior year resulting from the abnormal rainfall and flooding in North Dakota during the 2011 second quarter. The increased 2011 costs, coupled with reduced production from curtailed and shut-in wells in North Dakota during that time, resulted in higher per-unit production expenses in 2011 compared to 2012.

Production taxes and other expenses increased $83.6 million, or 58%, to $228.4 million for the year ended December 31, 2012 compared to the year ended December 31, 2011 as a result of higher crude oil and natural gas revenues resulting primarily from increased sales volumes. Production taxes and other expenses in the consolidated statements of income include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $29.9 million and $13.7 million for the years ended December 31, 2012 and 2011, respectively. The increase in other charges is primarily due to the significant increase in natural gas sales volumes in 2012. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.2% for the year ended December 31, 2012 compared to 7.9% for the year ended December 31, 2011. The increase was due to higher taxable revenues coming from North Dakota, our most active area, which has production tax rates of up to 11.5% of crude oil revenues.

On a unit of sales basis, production expenses and production taxes and other expenses were as follows:

	Year Ended December 31,	
$/Boe	2012	2011
Production expenses	$5.49	$6.13
Production taxes and other expenses	6.42	6.42
Production expenses, production taxes and other expenses	$11.91	$12.55

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

	Year Ended December 31,	
In thousands	2012	2011
Exploratory geological and geophysical costs	$22,740	$19,971
Dry hole costs	767	7,949
Exploration expenses	$23,507	$27,920

Exploratory geological and geophysical costs increased $2.8 million for the year ended December 31, 2012 due to an increase in acquisitions of seismic data in connection with our increased capital budget for 2012. No significant dry holes were drilled during 2012. Dry hole costs recognized in 2011 were primarily concentrated in Arkoma Woodford and Michigan.

Depreciation, depletion, amortization and accretion. Total DD&A increased $301.2 million, or 77%, for the year ended December 31, 2012 compared to the year ended December 31, 2011 primarily due to a 58% 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	2012	2011
Crude oil and natural gas properties	$19.10	$16.90
Other equipment	0.25	0.29
Asset retirement obligation accretion	0.09	0.14
Depreciation, depletion, amortization and accretion	$19.44	$17.33

The increase in DD&A per Boe was partially the result of a gradual shift in our production base from our historic base of the Red River units in the Cedar Hills field to newer production bases in the Bakken and Oklahoma Woodford plays. The producing properties in our newer areas typically carry higher DD&A rates due to the higher cost of developing reserves in those areas compared to our older, more mature properties.

Property impairments. Property impairments increased in the year ended December 31, 2012 by $13.8 million to $122.3 million compared to $108.5 million for the year ended December 31, 2011.

Impairments of non-producing properties increased $25.5 million for the year ended December 31, 2012 to $117.9 million compared to $92.4 million for the year ended December 31, 2011. The increase resulted from a larger base of amortizable costs in 2012 coupled with changes in management's estimates of the undeveloped properties not expected to be developed before lease expiration.

Impairment provisions for proved properties were $4.3 million for the year ended December 31, 2012 compared to $16.1 million for the same period in 2011. Impairments of proved properties in 2012 primarily reflected uneconomic operating results in a non-Woodford single-well field in our South region. Impairment provisions for proved properties in 2011 reflected uneconomic operating results for initial wells drilled on our acreage in the Niobrara play in Colorado.

General and administrative expenses. G&A expenses increased $48.9 million to $121.7 million for the year ended December 31, 2012 from $72.8 million for the comparable period in 2011. G&A expenses include non-cash charges for equity compensation of $29.1 million and $16.6 million for the years ended December 31, 2012 and 2011, respectively. The increase in equity compensation in 2012 resulted from a higher value of restricted stock grants due to employee growth and new executive management personnel, which resulted in increased expense recognition in 2012 compared to 2011. G&A expenses other than equity compensation increased $36.4 million for the year ended December 31, 2012 compared to the same period in 2011. The increase was due in part to an increase in personnel costs and office-related expenses associated with our rapid growth. In 2012, our Company grew from having 609 total employees in December 2011 to 753 total employees in December 2012, a 24% increase. Additionally, in March 2011 we announced plans to relocate our corporate headquarters from Enid, Oklahoma to Oklahoma City, Oklahoma. Our relocation was completed during 2012. For the year ended December 31, 2012, we recognized approximately $7.8 million of costs in G&A expenses associated with the relocation compared to $3.2 million in 2011. Cumulative relocation costs recognized through December 31, 2012 totaled approximately $11.0 million.

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	2012	2011
General and administrative expenses	$2.38	$2.36
Non-cash equity compensation	0.82	0.73
Corporate relocation expenses	0.22	0.14
Total general and administrative expenses	$3.42	$3.23

Interest Expense. Interest expense increased $64.0 million to $140.7 million for the year ended December 31, 2012 from $76.7 million for the comparable period in 2011 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, 2012 was approximately $2.3 billion with a weighted average interest rate of 5.6% compared to a weighted average outstanding long-term debt balance of approximately $970.0 million and a weighted average interest rate of 7.2% for the comparable period in 2011. The increase in outstanding debt resulted from borrowings incurred to fund increased amounts of capital expenditures and property acquisitions in 2012 compared to 2011. On March 8, 2012 and August 16, 2012, we issued $800 million and $1.2 billion, respectively, of 5% Senior Notes due 2022 and used the net proceeds from those issuances to repay credit facility borrowings, to fund a portion of our 2012 capital budget and for general corporate purposes.

Our weighted average outstanding credit facility balance increased to $322.1 million for the year ended December 31, 2012 compared to $70.0 million for the year ended December 31, 2011. The weighted average interest rate on our credit facility borrowings was 2.3% for the year ended December 31, 2012 compared to 2.4% for the same period in 2011. At December 31, 2012, we had $595 million of outstanding borrowings on our credit facility compared to $358.0 million outstanding at December 31, 2011. The increase in credit facility borrowings in 2012 was driven by the aforementioned increase in capital expenditures and property acquisitions during the year.

Income Taxes. We recorded income tax expense for the year ended December 31, 2012 of $415.8 million compared to $258.4 million for the year ended December 31, 2011, resulting in effective tax rates of approximately 36% and 38% for 2012 and 2011, 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, 2013, we had $28.5 million of cash and cash equivalents and $1.2 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $275 million of outstanding borrowings on our credit facility at December 31, 2013. As of February 17, 2014, we had $560 million of outstanding borrowings and approximately $936 million of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $2.6 billion and $1.6 billion for the years ended December 31, 2013 and 2012, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues driven by higher sales volumes and higher realized commodity prices, which were partially offset by an increase in cash losses on matured derivatives and increases in production expenses, production taxes, general and administrative expenses, interest expense and other expenses associated with the growth of our operations during the year.

Cash flows used in investing activities

During the years ended December 31, 2013 and 2012, we had cash flows used in investing activities (excluding proceeds from asset sales and other) of $3.74 billion and $4.12 billion, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $268.1 million and $1.1 billion for the years ended December 31, 2013 and 2012, respectively. In 2012 we executed certain transactions to acquire properties in North Dakota totaling $939 million, with no transactions of similar size in 2013. Cash capital expenditures excluding acquisitions totaled $3.47 billion and $2.99 billion for the years ended December 31, 2013 and

2012, respectively, the increase of which was driven by an increase in our capital budget for 2013.

The use of cash for capital expenditures during the year ended December 31, 2012 was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to $214.7 million for 2012, primarily related to our February 2012 disposition of certain Wyoming properties for proceeds of $84.4 million, our June 2012 disposition of certain Oklahoma properties for proceeds of $15.9 million, and our December 2012 disposition of certain East region properties for $126.4 million, of which $14.0 million had not been received at December 31, 2012. No significant asset dispositions occurred during the year ended December 31, 2013.

Cash flows from financing activities

Net cash provided by financing activities for the year ended December 31, 2013 totaled $1.1 billion, primarily resulting from the receipt of $1.48 billion of net proceeds from the issuance of $1.5 billion of 4 1/2% Senior Notes due 2023 in April 2013, partially offset by net repayments of $320.0 million on our credit facility during the year.

Net cash provided by financing activities of $2.3 billion for the year ended December 31, 2012 was primarily the result of $787.0 million of net proceeds received from the March 2012 issuance of $800 million of 5% Senior Notes due 2022 and an additional $1.21 billion of net proceeds received from the issuance of $1.2 billion of additional 2022 Notes at 102.375% of par in August 2012, along with $237.0 million of net borrowings made on our credit facility to fund a portion of our 2012 capital program.

Future Sources of Financing

Although we cannot provide any assurance, assuming sustained strength in crude oil prices and successful implementation of our business strategy, 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. 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 and derivative contracts we have in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, 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 a credit facility, maturing on July 1, 2015, that has aggregate lender commitments totaling $1.5 billion. In November 2013, following an upgrade by S&P, as permitted by the credit facility terms, we provided the lenders under our credit facility notice of our intention to elect an Additional Covenant Period. The election of an Additional Covenant Period means that the credit facility is not currently subject to a borrowing base. The election was made in order to facilitate the release of collateral consisting of oil and gas properties securing obligations under the credit facility. On December 11, 2013, we delivered notice to the credit facility lenders confirming we had satisfied all conditions for releasing the collateral and the release of such collateral became effective as of December 12, 2013. On December 13, 2013, our credit rating was upgraded by Moody's. As a result of the second upgrade, we are not currently required to: (i) comply with certain reporting requirements; and (ii) maintain a ratio of the present value of oil and gas properties to total funded debt of not less than 1.5 to 1.0, as set forth in the credit facility.

The credit facility's commitments of $1.5 billion can be increased up to $2.5 billion under the terms of the facility. The commitments are from a syndicate of 13 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. If one or more lenders cannot fund its commitment, we may not have the full availability of the $1.5 billion commitment.

We had $275 million of outstanding borrowings and $1.2 billion of borrowing availability (after considering outstanding borrowings and letters of credit) on our credit facility at December 31, 2013. As of February 17, 2014, we had $560 million of outstanding borrowings and $936 million of borrowing availability on our credit facility (after considering outstanding borrowings and letters of credit). The increase in outstanding borrowings subsequent to December 31, 2013 resulted from borrowings incurred to fund a portion of our 2014 capital program.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. Our credit facility also contains requirements that we maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 4.0 to 1.0. We were in compliance with these covenants at December 31, 2013 and expect to maintain compliance for at least the next 12 months. At December 31, 2013, our current ratio, as defined, was 1.7 to 1.0 and our total funded debt to EBITDAX ratio was 1.7 to 1.0. A violation of these covenants in the future could result in a default under our credit facility and such event could result in an acceleration of other outstanding indebtedness. In the event of such default, the lenders under our credit facility could elect to terminate their commitments thereunder, cease making further loans, and could declare all outstanding amounts, if any, to be due and payable. If outstanding borrowings under our credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. 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.

Our ability to remain in an Additional Covenant Period as described above is dependent on the credit ratings assigned to our senior unsecured debt. In the future, we may not be able to access adequate funding under our credit facility as a result of (i) a decrease in our credit ratings that nullifies our eligibility for the Additional Covenant Period and triggers the reinstatement of a borrowing base requirement, subjecting us to the risk that other events may adversely impact the size of our borrowing base, (ii) a decline in commodity prices, or (iii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations or increase their commitments as required under the credit facility.

If we are unable to access funding on acceptable terms when needed, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Derivative activities

As part of our risk management program, we economically hedge a portion of our anticipated future crude oil and natural gas production to achieve more predictable cash flows and to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy. See Note 5. Derivative Instruments in Notes to Consolidated Financial Statements for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts at December 31, 2013 and the estimated fair value of those contracts as of that date. Additionally, a summary of derivative contracts entered into after December 31, 2013 is provided subsequently under the heading Crude Oil and Natural Gas Hedging. We expect to continue entering into derivative instruments covering a portion of our future crude oil and/or natural gas production in order to further secure cash flows in support of our growth plans; however, we may choose not to hedge future production if the pricing environment for certain time periods is not deemed to be favorable.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $4.4 billion at December 31, 2013. Scheduled maturities of our senior notes begin in October 2019. 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, 2013 and expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants under the senior note indentures will materially limit our ability to undertake additional debt or equity financing.

Two of our subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have insignificant assets with no current value and no operations, fully and unconditionally guarantee the senior notes. Our other subsidiary, 20 Broadway Associates LLC, the value of whose assets and operations are minor, does 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, 2013, we invested approximately $3.57 billion in our capital program, excluding $268.1 million of unbudgeted acquisitions and including $28.4 million of seismic costs and $89.5 million of capital costs associated with increased accruals for capital expenditures. Our capital expenditures budget for 2013 was $3.60 billion, excluding acquisitions which are not budgeted. 2013 capital expenditures were allocated as follows:

In millions	Amount
Exploration and development drilling	$3,120.9
Land costs	295.4
Capital facilities, workovers and re-completions	66.9
Buildings, vehicles, computers and other equipment	61.9
Seismic (1)	28.4
Capital expenditures, excluding acquisitions	$3,573.5
Acquisitions of producing properties	16.6
Acquisitions of non-producing properties	251.5
Total acquisitions	268.1
Total capital expenditures	$3,841.6

(1) Includes $12.9 million of exploratory seismic costs recognized as exploration expense and $15.5 million of developmental seismic costs capitalized in conjunction with development drilling projects.

Our 2013 capital program focused primarily on increased exploration and development in the Bakken field of North Dakota and Montana and the SCOOP play in south-central Oklahoma.

In September 2013, our Board of Directors approved a 2014 capital expenditure budget of $4.05 billion excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$3,540
Land costs	300
Capital facilities, workovers and re-completions	150
Buildings, vehicles, computers and other equipment	30
Seismic	30
Total 2014 capital budget, excluding acquisitions	$4,050

Our 2014 capital plan is expected to continue focusing on exploratory and development drilling in the Bakken field and the SCOOP play.

Although we cannot provide any assurance, assuming sustained strength in crude oil prices and successful implementation of our business strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe funds from operating cash flows, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to fund our planned 2014 capital program; however, 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. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, 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. Further, 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, 2013:

	Payments due by period				
In thousands	Total	Less than 1 year (2014)	Years 2 and 3 (2015-2016)	Years 4 and 5 (2017-2018)	More than 5 years
Arising from arrangements on the balance sheet:					
Credit facility borrowings	$275,000	$ —	$275,000	$ —	$—
Senior Notes (1)	4,400,000	—	—	—	4,400,000
Note payable (2)	18,470	2,011	4,222	4,500	7,737
Interest expense (3)	1,956,796	240,701	474,857	471,643	769,595
Asset retirement obligations (4)	55,787	1,434	1,209	176	52,968
Arising from arrangements not on balance sheet:					
Operating leases and other (5)	7,027	3,811	2,628	406	182
Drilling rig commitments (6)	109,510	83,336	26,174	—	—
Fracturing and well stimulation services (7)	15,853	15,853	—	—	—
Pipeline transportation commitments (8)	67,290	16,188	28,992	10,010	12,100
Rail transportation commitments (9)	9,821	9,821	—	—	—
Cost sharing commitment (10)	24,538	14,925	9,613	—	—
Total contractual obligations	$6,940,092	$ 388,080	$822,695	$ 486,735	$5,242,582

(1) Amounts represent scheduled maturities of our senior note obligations at December 31, 2013 and do not reflect any discount or premium at which the senior notes were issued. See 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 expense includes 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, 2013 and assumes the actual weighted average interest rate on our credit facility borrowings of 1.7% at December 31, 2013 continues through the July 1, 2015 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 Notes to Consolidated Financial Statements—Note 1. Organization and Summary of Significant Accounting Policies for additional discussion of our asset retirement obligations.

(5) Amounts primarily represent leases for office equipment, communication towers and tanks for storage of hydraulic fracturing fluids, in addition to purchase obligations mainly related to software services.

(6) Amounts represent commitments under drilling rig contracts with various terms extending through January 2016. 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.

(7) 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 2014, 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.

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

per-unit transportation charges regardless of the amount of pipeline capacity used. We are not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future. See Notes to Consolidated Financial Statements—Note 10. Commitments and Contingencies for additional discussion.

(9) We have entered into firm transportation commitments to guarantee capacity on rail transportation facilities in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The rail commitments require us to pay varying per-barrel transportation charges regardless of the amount of rail capacity used. We are not committed under these contracts to deliver fixed and determinable quantities of crude oil in the future. See 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.

In addition to the operational pipeline transportation commitments described above, we are a party to 5-year firm transportation commitments for future crude oil pipeline projects that are being constructed or considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require significant additional construction efforts by the counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.0 billion at December 31, 2013, representing aggregate transportation charges expected to be incurred over the 5-year terms of the arrangements assuming the proposed pipeline projects are completed and become operational. The exact timing of the commencement of pipeline operations is not known due to uncertainties involving matters such as regulatory approvals, resolution of legal and environmental disputes, construction progress and the ultimate probability of pipeline completion. Accordingly, the timing of our obligations under these non-operational arrangements 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. For these reasons, these obligations have not been reflected in the contractual obligations table above. Although timing is uncertain, operators have indicated that certain pipeline projects may become operational in the fourth quarter of 2014, which would obligate us for transportation charges totaling $36 million in 2014, $143 million per year in years 2015 through 2018, and $106 million in 2019 associated with those projects.

Crude Oil and Natural Gas Hedging

As part of our risk management program, we economically hedge a portion of our anticipated future crude oil and natural gas production to achieve more predictable cash flows and to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. While the use of hedging arrangements limits the downside risk of adverse price movements, their use also limits future revenues from upward price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. All of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our credit facility. For a discussion of the potential risks associated with our hedging program, refer to Part I, Item 1A. Risk Factors—Our derivative activities could result in financial losses or reduce our earnings.

Our 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. See Notes to Consolidated Financial Statements—Note 5. Derivative Instruments for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts as of December 31, 2013 and the estimated fair value of the contracts as of that date.

Between January 1, 2014 and February 17, 2014, we entered into additional derivative contracts summarized in the tables below. None of these contracts have been designated for hedge accounting.

Crude Oil—ICE Brent

Period and Type of Contract	Bbls	Weighted Average Price
January 2015 - December 2015		
Swaps - ICE Brent	6,205,000	$100.27

Natural Gas—NYMEX Henry Hub

Period and Type of Contract	MMBtus	Weighted Average Price
January 2014 - December 2014		
Swaps - Henry Hub	40,495,000	$4.26

January 2015 - December 2015		
Swaps - Henry Hub	22,700,000	$4.27
January 2016 - December 2016		
Swaps - Henry Hub	4,550,000	$4.27

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. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires our management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure and estimation of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of existing rules must be done and judgments must be made on how the specifics of a given rule apply to us.

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. 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. 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 and internal technical staff prepare the estimates of our crude oil and natural gas reserves and associated future net cash flows. Even though our external independent reserve engineers and 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. 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. 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.

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. We use the sales method of accounting for natural gas imbalances in those circumstances where we have under-produced or over-produced our 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.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for our 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.

Depreciation, depletion, and amortization of capitalized drilling and development costs of crude oil and natural gas properties, including related support equipment and facilities, are generally computed using the unit-of-production method on a field basis based on total estimated proved developed crude oil and natural gas 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 our internal geologists and engineers and external independent reserve engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 3 to 40 years. Upon sale or retirement of depreciable or depletable property, 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.

Derivative Activities

We 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. In addition, we may utilize basis contracts to hedge the differential between NYMEX posted prices and those of our physical pricing points. We do not use derivative instruments for trading purposes. Under accounting rules, we may elect to designate those derivatives that qualify for hedge accounting as cash flow hedges against the price we will receive for 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. As such, we are likely to experience significant non-cash volatility in our reported earnings during periods of commodity price volatility. Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on our consolidated balance sheets.

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 calculation of the fair value of our collar contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the derivative agreements and the resulting estimated future cash inflows or outflows over the lives of the derivatives are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates. We validate our derivative valuations through management review and by comparison to our counterparties’ valuations for reasonableness.

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. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was assessed. 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 that 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, 2013, we believe all deferred tax assets 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 that are 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

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 2014 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, and accounting for 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. Laws, rules, regulations, policies, and interpretations affecting our industry have been pervasive and are continuously reviewed by legislators and regulators, including the imposition of new or increased requirements on us and other industry participants. 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. We believe we are in substantial compliance with all laws and regulations and policies currently applicable to our operations and our continued compliance with existing requirements will not have a material adverse impact on us. However, because public policy changes affecting our industry are commonplace and because laws and regulations may be amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws and regulations.

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, particularly in the North region, and competitive pressures resulting from higher crude oil prices and may again in the future.

Non-GAAP Financial Measures

EBITDAX

We present EBITDAX throughout this Annual Report on Form 10-K, which is a non-GAAP financial measure. EBITDAX represents 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, and non-cash equity compensation expense. 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. 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 credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

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. Our credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 4.0 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our credit facility plus our note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant at December 31, 2013.

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

	Year Ended December 31,				
In thousands	2013	2012	2011	2010	2009
Net income	$764,219	$739,385	$429,072	$168,255	$71,338
Interest expense	235,275	140,708	76,722	53,147	23,232
Provision for income taxes	448,830	415,811	258,373	90,212	38,670
Depreciation, depletion, amortization and accretion	965,645	692,118	390,899	243,601	207,602
Property impairments	220,508	122,274	108,458	64,951	83,694
Exploration expenses	34,947	23,507	27,920	12,763	12,615
Impact from derivative instruments:					
Total (gain) loss on derivatives, net	191,751	(154,016)	30,049	130,762	1,520
Total cash (paid) received on derivatives, net	(61,555)	(45,721)	(34,106)	35,495	569
Non-cash (gain) loss on derivatives, net	130,196	(199,737)	(4,057)	166,257	2,089
Non-cash equity compensation	39,890	29,057	16,572	11,691	11,408
EBITDAX	$2,839,510	$1,963,123	$1,303,959	$810,877	$450,648

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	2013	2012	2011	2010	2009
Net cash provided by operating activities	$2,563,295	$1,632,065	$1,067,915	$653,167	$372,986
Current income tax provision	6,209	10,517	13,170	12,853	2,551
Interest expense	235,275	140,708	76,722	53,147	23,232
Exploration expenses, excluding dry hole costs	25,597	22,740	19,971	9,739	6,138
Gain on sale of assets, net	88	136,047	20,838	29,588	709
Excess tax benefit from stock-based compensation	—	15,618	—	5,230	2,872
Other, net	(1,829)	(7,587)	(4,606)	(3,513)	(3,890)
Changes in assets and liabilities	10,875	13,015	109,949	50,666	46,050
EBITDAX	$2,839,510	$1,963,123	$1,303,959	$810,877	$450,648

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, 2013, our PV-10 totaled approximately $20.2 billion. The Standardized Measure of our discounted future net cash flows was approximately $16.3 billion at December 31, 2013, representing a $3.9 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 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, 2013 and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $350 million for each $10.00 per barrel change in crude oil prices and $88 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by these market fluctuations, we 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 ensure we have adequate funds available 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. While hedging 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, 2013 had an overall negative impact on the fair value of our derivative instruments. For the year ended December 31, 2013, we recognized cash losses on derivatives of $61.6 million and reported a non-cash mark-to-market loss on derivatives of $130.2 million. The fair value of our derivative instruments at December 31, 2013 was a net liability of $94.7 million. The mark-to-market net liability relates to derivative instruments with various terms that are scheduled to mature over the period from January 2014 through December 2015. Over this period, actual derivative settlements may differ significantly, either positively or negatively, from the mark-to-market valuation at December 31, 2013. An assumed increase in the forward commodity prices used in the year-end valuation of our derivative instruments of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative liability to approximately $485 million at December 31, 2013. Conversely, an assumed decrease in forward commodity prices of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would change our derivative valuation to a net asset of approximately $289 million at December 31, 2013.

For a further discussion of our hedging activities, see Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Crude Oil and Natural Gas Hedging and Part II, Item 8. Notes to Consolidated Financial Statements—Note 5. Derivative Instruments.

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 ($656.2 million in receivables at December 31, 2013), our joint interest receivables ($350.0 million at December 31, 2013), and counterparty credit risk associated with our derivative instrument receivables ($3.6 million at December 31, 2013).

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 support 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 entities which own a partial interest in the wells we operate. These 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 $57.2 million as of

December 31, 2013, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We also 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. All of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our credit facility.

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 $560 million of outstanding borrowings under our credit facility at February 17, 2014. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $5.6 million per year and a $3.5 million decrease in net income per year. Our credit facility matures on July 1, 2015 and the weighted-average interest rate on outstanding borrowings at February 17, 2014 was 1.7%.

The following table presents our debt maturities and the weighted average interest rates by expected maturity date as of December 31, 2013:

In thousands	2014	2015	2016	2017	2018	Thereafter	Total
Fixed rate debt:							
Senior Notes:							
Principal amount (1)	$—	$—	$—	$—	$—	$4,400,000	$4,400,000
Weighted-average interest rate	—	—	—	—	—	5.4 %	5.4 %
Note payable:							
Principal amount	$2,011	$2,078	$2,144	$2,214	$2,286	$7,737	$18,470
Interest rate	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %	3.1 %
Variable rate debt:							
Credit facility:							
Principal amount	$—	$275,000	$—	$—	$—	$—	$275,000
Weighted-average interest rate	—	1.7 %	—	—	—	—	1.7 %

(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. 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, 2013 and 2012, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in the 1992 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 26, 2014 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 26, 2014

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31,	
In thousands, except par values and share data	2013	2012
Assets		
Current assets:		
Cash and cash equivalents	$28,482	$35,729
Receivables:		
Crude oil and natural gas sales	643,498	468,650
Affiliated parties	13,107	12,410
Joint interest and other, net	349,579	356,111
Derivative assets	3,616	18,389
Inventories	54,440	46,743
Deferred and prepaid taxes	44,337	365
Prepaid expenses and other	10,207	8,386
Total current assets	1,147,266	946,783
Net property and equipment, based on successful efforts method of accounting	10,721,272	8,105,269
Net debt issuance costs and other	72,644	55,726
Noncurrent derivative assets	—	32,231
Total assets	$11,941,182	$9,140,009
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable trade	$885,289	$687,310
Revenues and royalties payable	291,772	261,856
Payables to affiliated parties	5,436	6,069
Accrued liabilities and other	198,113	155,681
Derivative liabilities	90,535	12,999
Current portion of long-term debt	2,011	1,950
Total current liabilities	1,473,156	1,125,865
Long-term debt, net of current portion	4,713,821	3,537,771
Other noncurrent liabilities:		
Deferred income tax liabilities	1,736,812	1,262,576
Asset retirement obligations, net of current portion	54,353	44,944
Noncurrent derivative liabilities	7,829	2,173
Other noncurrent liabilities	2,093	2,981
Total other noncurrent liabilities	1,801,087	1,312,674
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; 185,658,659 shares issued and outstanding at December 31, 2013; 185,604,681 shares issued and outstanding at December 31, 2012	1,857	1,856
Additional paid-in capital	1,252,034	1,226,835
Retained earnings	2,699,227	1,935,008
Total shareholders' equity	3,953,118	3,163,699
Total liabilities and shareholders' equity	$11,941,182	$9,140,009

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

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Income

	Year Ended December 31,		
In thousands, except per share data	2013	2012	2011
Revenues:			
Crude oil and natural gas sales	$3,501,666	$2,315,840	$1,553,629
Crude oil and natural gas sales to affiliates	105,108	63,593	93,790
Gain (loss) on derivative instruments, net	(191,751)	154,016	(30,049)
Crude oil and natural gas service operations	40,127	39,071	32,419
Total revenues	3,455,150	2,572,520	1,649,789
Operating costs and expenses:			
Production expenses	280,789	193,466	135,178
Production and other expenses to affiliates	6,111	6,675	4,632
Production taxes and other expenses	327,427	223,737	143,236
Exploration expenses	34,947	23,507	27,920
Crude oil and natural gas service operations	29,665	32,248	26,735
Depreciation, depletion, amortization and accretion	965,645	692,118	390,899
Property impairments	220,508	122,274	108,458
General and administrative expenses	144,379	121,735	72,817
Gain on sale of assets, net	(88)	(136,047)	(20,838)
Total operating costs and expenses	2,009,383	1,279,713	889,037
Income from operations	1,445,767	1,292,807	760,752
Other income (expense):			
Interest expense	(235,275)	(140,708)	(76,722)
Other	2,557	3,097	3,415
	(232,718)	(137,611)	(73,307)
Income before income taxes	1,213,049	1,155,196	687,445
Provision for income taxes	448,830	415,811	258,373
Net income	$764,219	$739,385	$429,072
Basic net income per share	$4.15	$4.08	$2.42
Diluted net income per share	$4.13	$4.07	$2.41

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	Retained earnings	Total shareholders' equity
Balance at December 31, 2010	170,408,652	$1,704	$439,900	$766,551	$1,208,155
Net income	—	—	—	429,072	429,072
Public offering of common stock	10,080,000	101	659,131	—	659,232
Stock-based compensation	—	—	16,567	—	16,567
Stock options:					
Exercised	18,470	—	13	—	13
Repurchased and canceled	(2,495)	—	(150)	—	(150)
Restricted stock:					
Issued	491,315	5	—	—	5
Repurchased and canceled	(82,807)	(1)	(4,767)	—	(4,768)
Forfeited	(41,447)	—	—	—	—
Balance at December 31, 2011	180,871,688	$1,809	$1,110,694	$1,195,623	$2,308,126
Net income	—	—	—	739,385	739,385
Common stock issued in exchange for assets	3,916,157	39	81,489	—	81,528
Stock-based compensation	—	—	30,209	—	30,209
Excess tax benefit on stock-based compensation	—	—	15,618	—	15,618
Stock options:					
Exercised	86,500	—	60	—	60
Repurchased and canceled	(32,984)	—	(2,951)	—	(2,951)
Restricted stock:					
Issued	916,028	9	—	—	9
Repurchased and canceled	(112,521)	(1)	(8,284)	—	(8,285)
Forfeited	(40,187)	—	—	—	—
Balance at December 31, 2012	185,604,681	$1,856	$1,226,835	$1,935,008	$3,163,699
Net income	—	—	—	764,219	764,219
Stock-based compensation	—	—	39,888	—	39,888
Restricted stock:					
Issued	261,259	3	—	—	3
Repurchased and canceled	(138,525)	(1)	(14,689)	—	(14,690)
Forfeited	(68,756)	(1)	—	—	(1)
Balance at December 31, 2013	185,658,659	$1,857	$1,252,034	$2,699,227	$3,953,118

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

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

In thousands	Year Ended December 31, 2013	2012	2011
Cash flows from operating activities:			
Net income	$764,219	$739,385	$429,072
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	965,437	694,698	391,844
Property impairments	220,508	122,274	108,458
Non-cash (gain) loss on derivatives, net	130,196	(199,737)	(4,057)
Stock-based compensation	39,890	29,057	16,572
Provision for deferred income taxes	442,621	405,294	245,203
Excess tax benefit from stock-based compensation	—	(15,618)	—
Dry hole costs	9,350	767	7,949
Gain on sale of assets, net	(88)	(136,047)	(20,838)
Other, net	2,037	5,007	3,661
Changes in assets and liabilities:			
Accounts receivable	(166,138)	(91,791)	(294,702)
Inventories	(7,697)	(7,165)	(3,412)
Prepaid expenses and other	(11,537)	14,381	(3,329)
Accounts payable trade	107,250	(8,487)	83,907
Revenues and royalties payable	28,401	40,030	88,976
Accrued liabilities and other	44,260	40,309	20,784
Other noncurrent assets and liabilities	(5,414)	(292)	(2,173)
Net cash provided by operating activities	2,563,295	1,632,065	1,067,915
Cash flows from investing activities:			
Exploration and development	(3,660,773)	(3,493,652)	(1,925,577)
Purchase of producing crude oil and natural gas properties	(16,604)	(570,985)	(65,315)
Purchase of other property and equipment	(62,054)	(53,468)	(44,750)
Proceeds from sale of assets and other	28,420	214,735	30,928
Net cash used in investing activities	(3,711,011)	(3,903,370)	(2,004,714)
Cash flows from financing activities:			
Revolving credit facility borrowings	970,000	2,119,000	493,000
Repayment of revolving credit facility	(1,290,000)	(1,882,000)	(165,000)
Proceeds from issuance of Senior Notes	1,479,375	1,999,000	—
Proceeds from issuance of common stock	—	—	659,736
Proceeds from other debt	—	22,000	—
Repayment of other debt	(1,951)	(1,579)	—
Debt issuance costs	(2,265)	(7,373)	(36)
Equity issuance costs	—	—	(368)
Repurchase of equity grants	(14,690)	(11,236)	(4,918)
Excess tax benefit from stock-based compensation	—	15,618	—
Exercise of stock options	—	60	13
Net cash provided by financing activities	1,140,469	2,253,490	982,427
Net change in cash and cash equivalents	(7,247)	(17,815)	45,628
Cash and cash equivalents at beginning of period	35,729	53,544	7,916

Cash and cash equivalents at end of period	$28,482	$35,729	$53,544

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.
The Company’s operations are geographically concentrated in the North region, with that region comprising approximately 77% of the Company’s crude oil and natural gas production and approximately 86% of its crude oil and natural gas revenues for the year ended December 31, 2013. Additionally, as of December 31, 2013 approximately 76% of the Company’s estimated proved reserves were located in the North region.
The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the year ended December 31, 2013, crude oil accounted for approximately 71% of the Company’s total production and approximately 87% of its crude oil and natural gas revenues. Crude oil represents approximately 68% of the Company's estimated proved reserves as of December 31, 2013.
Basis of presentation of consolidated financial statements
The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are 100% owned, after all significant intercompany accounts and transactions have been eliminated upon consolidation.
Use of estimates
The preparation of financial statements in conformity with accounting principles generally accepted in the United States (“U.S. GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates. The most significant of the estimates and assumptions that affect reported results are the estimates of the Company’s crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved crude oil and natural gas properties. 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, 2013 and 2012 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, 2013, the Company had cash deposits in excess of federally insured amounts of approximately $28.0 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 years ended December 31, 2013, 2012 and 2011, sales to the Company's largest purchaser accounted for approximately 15%, 21% and 41% of total crude oil and natural gas sales, respectively. Additionally, for the years ended December 31, 2013 and 2012 the Company's second largest purchaser accounted for approximately 12% and 11%, respectively, of its total crude oil and natural gas sales. The Company's third largest purchaser accounted for approximately 11% of total crude oil and natural gas sales for the year ended December 31, 2013. No other purchasers accounted for more than 10% of the Company's total crude oil and natural gas sales for 2011, 2012 and 2013. 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	2013	2012
Tubular goods and equipment	$11,139	$13,590
Crude oil	43,301	33,153
Total	$54,440	$46,743

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	2013	2012
Crude oil line fill requirements	370	391
Temporarily stored crude oil	344	211
Total	714	602

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. Total capitalized exploratory drilling costs pending the determination of proved reserves were $152.8 million and $92.7 million as of December 31, 2013 and 2012, respectively. As of December 31, 2013, exploratory drilling costs of $3.9 million, representing 3 wells, were suspended one year beyond the completion of drilling and are expected to be fully evaluated in 2014. Of the suspended costs, $0.5 million was incurred in 2013, $1.5 million was incurred in 2012, none in 2011 and $1.9 million was incurred in 2010.

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, 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 crude oil and natural gas 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, 2011 through December 31, 2013:

In thousands	2013	2012	2011
Asset retirement obligations at January 1	$47,171	$62,625	$56,320
Accretion expense	2,767	3,105	3,163
Revisions	2,826	(2,871)	1,947
Plus: Additions for new assets	6,009	6,679	3,559
Less: Plugging costs and sold assets (1)	(2,986)	(22,367)	(2,364)
Total asset retirement obligations at December 31	$55,787	$47,171	$62,625
Less: Current portion of asset retirement obligations at December 31 (2)	1,434	2,227	2,287
Non-current portion of asset retirement obligations at December 31	$54,353	$44,944	$60,338

(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, 2013 and 2012, net property and equipment on the consolidated balance sheets included $44.4 million and $36.6 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. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on management's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips, operating and development costs, and a risk-adjusted discount rate.

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 issuance of the 8 1/4% Senior Notes due 2019, the 7 3/8% Senior Notes due 2020, the 7 1/8% Senior Notes due 2021, the 5% Senior Notes due 2022 and the 4 1/2% Senior Notes due 2023 (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 $69.5 million and $55.3 million (net of accumulated amortization of $28.8 million and $20.2 million) relating to its long-term debt at December 31, 2013 and 2012, respectively. The increase in 2013 resulted from the capitalization of costs incurred in connection with the Company's April 2013 issuance of 4 1/2% Senior Notes due 2023 as discussed in Note 7. Long-Term Debt. For the years ended December 31, 2013, 2012 and 2011, the Company recognized amortization expense associated with capitalized debt issuance costs of $8.6 million, $5.6 million and $3.3 million, respectively, which are reflected in "Interest expense" in the consolidated statements of income.

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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. Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the consolidated balance sheets. The 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 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. The carrying values of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short term maturity of those instruments. The fair value of derivative contracts is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars, volatility, the risk-free interest rate, and the time to expiration. See Note 5. Derivative Instruments for quantification of the fair value of the Company’s derivative instruments at December 31, 2013 and 2012.
Long-term debt consists of the Company’s Notes, its note payable, and borrowings on its credit facility. The fair values of the Notes are based on quoted market prices. The fair value of the note payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the note payable and an assumed discount rate. The fair value of credit facility borrowings approximates carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities. See Note 6. Fair Value Measurements for quantification of the fair value of the Company’s long-term debt obligations at December 31, 2013 and 2012.
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 as if the awards and options were exercised. 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, 2013, 2012 and 2011. All stock options issued by the Company in prior periods had been exercised or had expired as of March 31, 2012.

	Year ended December 31,		
In thousands, except per share data	2013	2012	2011
Income (numerator):			
Net income - basic and diluted	$764,219	$739,385	$429,072
Weighted average shares (denominator):			
Weighted average shares - basic	184,075	181,340	177,590
Non-vested restricted stock	774	490	544
Stock options	—	16	96

Weighted average shares - diluted	184,849	181,846	178,230
Net income per share:			
Basic	$4.15	$4.08	$2.42
Diluted	$4.13	$4.07	$2.41

Adoption of new accounting standard

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-11, Balance Sheet (Topic 210)–Disclosures about Offsetting Assets and Liabilities. The new standard requires an entity to disclose information about offsetting arrangements to enable financial statement users to understand the effect of netting arrangements on an entity's financial position. The disclosures are required for recognized financial instruments and derivative instruments that are subject to offsetting or are subject to master netting arrangements irrespective of whether they are offset. The disclosure requirements became effective January 1, 2013 and must be applied retrospectively to all periods presented on the balance sheet. The Company adopted the provisions of the new standard on January 1, 2013 and has included the required disclosures in Note 5. Derivative Instruments. Adoption of the new standard required additional footnote disclosures for the Company's derivative instruments and did not have an impact on its financial position, results of operations 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	2013	2012	2011
Supplemental cash flow information:			
Cash paid for interest	$209,815	$102,043	$70,088
Cash paid for income taxes	29,017	829	16,030
Cash received for income tax refunds	(174)	(13,866)	(116)
Non-cash investing activities:			
Increase in accrued capital expenditures	89,482	49,039	173,591
Acquisition of assets through issuance of common stock (Note 14)	—	176,563	—
Asset retirement obligation additions and revisions, net	8,835	3,808	5,506

Note 3. Net Property and Equipment

Net property and equipment includes the following at December 31, 2013 and 2012:

	December 31,	
In thousands	2013	2012
Proved crude oil and natural gas properties	$ 12,423,878	$ 8,980,505
Unproved crude oil and natural gas properties	1,181,268	1,073,944
Service properties, equipment and other	236,233	170,763
Total property and equipment	13,841,379	10,225,212
Accumulated depreciation, depletion and amortization	(3,120,107)	(2,119,943)
Net property and equipment	$ 10,721,272	$ 8,105,269

Note 4. Accrued Liabilities and Other

Accrued liabilities and other includes the following at December 31, 2013 and 2012:

	December 31,	
In thousands	2013	2012
Prepaid advances from joint interest owners	$ 57,196	$ 30,434
Accrued compensation	41,757	27,797
Accrued production taxes, ad valorem taxes and other non-income taxes	35,900	33,466
Accrued income taxes	—	10,455
Accrued interest	61,216	46,973
Current portion of asset retirement obligations	1,434	2,227
Other	610	4,329
Accrued liabilities and other	$ 198,113	$ 155,681

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

The Company has utilized 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, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars requires the use of an option-pricing model. See Note 6. Fair Value Measurements.

At December 31, 2013, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil–NYMEX WTI		Swaps Weighted
Period and Type of Contract	Bbls	Average Price
January 2014 - December 2014		
Swaps - WTI	10,851,250	$96.50

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Crude Oil–ICE Brent		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
January 2014 - December 2014						
Swaps - ICE Brent	17,028,000	$103.17				
Collars - ICE Brent	2,190,000		$90.00 - $95.00	$90.83	$104.70 - $108.85	$107.13
January 2015 - December 2015						
Swaps - ICE Brent	2,737,500	$99.15				
Collars - ICE Brent	730,000		$95.00	$95.00	$107.40	$107.40

Natural Gas–NYMEX Henry Hub Period and Type of Contract	MMBtus	Swaps Weighted Average Price
January 2014 - December 2014		
Swaps - Henry Hub	64,250,000	$4.19
January 2015 - March 2015		
Swaps - Henry Hub	1,800,000	$4.27

Derivative gains and losses

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

	Year ended December 31,		
In thousands	2013	2012	2011
Cash received (paid) on derivatives:			
Crude oil fixed price swaps	$(54,289)	$(40,238)	$(14,900)
Crude oil collars	(16,867)	(15,341)	(56,511)
Natural gas fixed price swaps	9,601	9,858	37,305
Cash paid on derivatives, net	$(61,555)	$(45,721)	$(34,106)
Non-cash gain (loss) on derivatives:			
Crude oil fixed price swaps	$(117,580)	$142,567	$(23,486)
Crude oil collars	(8,587)	59,911	42,239
Natural gas fixed price swaps	(4,029)	(2,741)	(14,696)
Non-cash gain (loss) on derivatives, net	$(130,196)	$199,737	$4,057
Gain (loss) on derivative instruments, net	$(191,751)	$154,016	$(30,049)

Balance sheet offsetting of derivative assets and liabilities

In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 210)-Disclosures about Offsetting Assets and Liabilities, which requires an entity to disclose information about offsetting arrangements to enable financial statement users to understand the effect of netting arrangements on an entity's financial position. The Company adopted the provisions of the new standard on January 1, 2013 as required and has provided the applicable disclosures below with respect to its derivative instruments.

All of the Company's derivative contracts are carried at their fair value in the consolidated balance sheets under the captions "Derivative assets", "Noncurrent derivative assets", "Derivative liabilities", and "Noncurrent derivative liabilities". Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the consolidated balance sheets.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets for the periods presented, all at fair value.

	December 31, 2013			December 31, 2012		
In thousands	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet
Commodity derivative assets	$4,213	$(597)	$3,616	$86,506	$(35,886)	$50,620

	December 31, 2013			December 31, 2012		
In thousands	Gross amounts of recognized liabilities	Gross amounts offset on balance sheet	Net amounts of liabilities on balance sheet	Gross amounts of recognized liabilities	Gross amounts offset on balance sheet	Net amounts of liabilities on balance sheet
Commodity derivative liabilities	$(125,709)	$27,345	$(98,364)	$(16,241)	$1,069	$(15,172)

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

In thousands	December 31, 2013	December 31, 2012
Derivative assets	$3,616	$18,389
Noncurrent derivative assets	—	32,231
Net amounts of assets on balance sheet	3,616	50,620
Derivative liabilities	(90,535)	(12,999)
Noncurrent derivative liabilities	(7,829)	(2,173)
Net amounts of liabilities on balance sheet	(98,364)	(15,172)
Total derivative assets (liabilities), net	$(94,748)	$35,448

Note 6. Fair Value Measurements

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

- Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
-

Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

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

Assets and liabilities measured at fair value on a recurring basis

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

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012.

In thousands	Fair value measurements at December 31, 2013 using:			
Description	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$(84,893)	$—	$(84,893)
Collars	—	(9,855)	—	(9,855)
Total	$—	$(94,748)	$—	$(94,748)

In thousands	Fair value measurements at December 31, 2012 using:			
Description	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$36,716	$—	$36,716
Collars	—	(1,268)	—	(1,268)
Total	$—	$35,448	$—	$35,448

Assets measured at fair value on a nonrecurring basis

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

Asset impairments – Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter, 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. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on management's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips, operating and development costs, and a risk-adjusted discount rate. The fair value of proved crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3). The following table sets forth quantitative information about the significant unobservable inputs used by the Company to calculate the fair value of proved crude oil and natural gas properties using a discounted cash flow method.

Unobservable Input	Assumption
Future production	Future production estimates for each property

Forward commodity prices	Forward NYMEX swap prices through 2018 (adjusted for differentials), escalating 3% per year thereafter
Operating and development costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of field	Ranging from 0 to 50 years
Discount rate	10%

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

Impairments of proved properties amounted to $51.8 million for the year ended December 31, 2013. Such impairments primarily reflected fair value adjustments made for certain properties in the Niobrara play in Colorado and Wyoming driven by uneconomic well results. The impaired properties were written down to their estimated fair value totaling approximately $21.2 million.

Certain unproved crude oil and natural gas properties were impaired during the years ended December 31, 2013 and 2012, primarily reflecting recurring amortization of undeveloped leasehold costs on properties that management expects will not be transferred to proved properties over the lives of the leases based on experience of successful drilling and the average holding period. Additionally, undeveloped leasehold costs on certain properties in the Niobrara play were individually assessed for impairment in the 2013 fourth quarter based on indicators of impairment and were written down to fair value of $14.9 million, which resulted in $8.4 million of impairment charges being recognized in addition to the recurring amortization described above.

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

	Year ended December 31,		
In thousands	2013	2012	2011
Proved property impairments	$51,805	$4,332	$16,107
Unproved property impairments	168,703	117,942	92,351
Total	$220,508	$122,274	$108,458

Financial instruments not recorded at fair value

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

	December 31, 2013		December 31, 2012	
In thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Credit facility	$275,000	$275,000	$595,000	$595,000
Note payable	18,470	16,500	20,421	20,148
8 1/4% Senior Notes due 2019	298,305	327,800	298,085	339,000
7 3/8% Senior Notes due 2020	198,695	223,700	198,552	226,833
7 1/8% Senior Notes due 2021	400,000	450,300	400,000	454,333
5% Senior Notes due 2022	2,025,362	2,063,300	2,027,663	2,165,833
4 1/2% Senior Notes due 2023	1,500,000	1,519,400	—	—
Total debt	$4,715,832	$4,876,000	$3,539,721	$3,801,147

The fair value of credit facility borrowings approximates carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

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

The fair values of the 8 1/4% Senior Notes due 2019 ("2019 Notes"), the 7 3/8% Senior Notes due 2020 ("2020 Notes"), the 7 1/8% Senior Notes due 2021 ("2021 Notes"), the 5% Senior Notes due 2022 ("2022 Notes"), and the 4 1/2% Senior Notes due 2023 ("2023 Notes") are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

The carrying values of all classes of cash and cash equivalents, trade receivables, and trade payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.

Note 7. Long-Term Debt

Long-term debt consists of the following at December 31, 2013 and 2012:

	December 31,	
In thousands	2013	2012
Credit facility	$275,000	$595,000
Note payable	18,470	20,421
8 1/4% Senior Notes due 2019 (1)	298,305	298,085
7 3/8% Senior Notes due 2020 (2)	198,695	198,552
7 1/8% Senior Notes due 2021 (3)	400,000	400,000
5% Senior Notes due 2022 (4)	2,025,362	2,027,663
4 1/2% Senior Notes due 2023 (3)	1,500,000	—
Total debt	4,715,832	3,539,721
Less: Current portion of long-term debt	(2,011)	(1,950)
Long-term debt, net of current portion	$4,713,821	$3,537,771

(1) The carrying amount is net of unamortized discounts of $1.7 million and $1.9 million at December 31, 2013 and 2012, respectively.

(2) The carrying amount is net of unamortized discounts of $1.3 million and $1.4 million at December 31, 2013 and 2012, respectively.

(3) These notes were sold at par and are recorded at 100% of face value.

(4) The carrying amount includes an unamortized premium of $25.4 million and $27.7 million at December 31, 2013 and 2012, respectively.

Credit facility

The Company has a credit facility, maturing on July 1, 2015, with aggregate lender commitments totaling $1.5 billion, which can be increased up to $2.5 billion under the terms of the facility. In November 2013, following an upgrade by Standard & Poor’s Rating Services (“S&P”), as permitted by the credit facility terms, the Company provided the lenders under its credit facility notice of its intention to elect an Additional Covenant Period (as defined in the credit facility). The election of an Additional Covenant Period means that the credit facility is not currently subject to a borrowing base. The election was made in order to facilitate the release of collateral consisting of oil and gas properties securing obligations under the credit facility. On December 11, 2013, the Company delivered notice to the credit facility lenders confirming it had satisfied all conditions for releasing the collateral and the release of such collateral became effective as of December 12, 2013. On December 13, 2013, the Company's credit rating was upgraded by Moody's Investor Services, Inc (“Moody’s”). As a result of the second upgrade, the Company is not currently required to: (i) comply with certain reporting requirements; and (ii) maintain a ratio of the present value of oil and gas properties to total funded debt of not less than 1.5 to 1.0, as set forth in the credit facility.

The Company had $275 million and $595 million of outstanding borrowings on its credit facility at December 31, 2013 and 2012, respectively. Borrowings under the facility at December 31, 2013 bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin of 150 basis points, or the lead bank’s reference rate (prime) plus a margin 50 basis points.

The Company had approximately $1.2 billion of unused commitments (after considering outstanding borrowings and letters of credit) under its credit facility at December 31, 2013 and incurs commitment fees of 0.25% per annum of the daily average amount of unused borrowing availability. The credit agreement contains certain restrictive covenants including a requirement that the Company maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 4.0 to 1.0. As defined by the credit facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit facility and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents 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, and non-cash equity compensation expense. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit on the credit facility plus the Company's note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. The Company was in compliance with these covenants at December 31, 2013.

Senior notes

In April 2013, the Company issued $1.5 billion of 4 1/2% Senior Notes due 2023 and received net proceeds of approximately $1.48 billion after deducting the initial purchasers' fees. The Company used the net proceeds from the offering to repay all borrowings then outstanding under its credit facility, which had a balance prior to payoff of approximately $1.04 billion, to fund a portion of its 2013 capital budget, and for general corporate purposes.

The following table summarizes the maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company's outstanding senior note obligations.

	2019 Notes	2020 Notes	2021 Notes	2022 Notes	2023 Notes
Maturity date	Oct 1, 2019	Oct 1, 2020	April 1, 2021	Sep 15, 2022	April 15, 2023
Interest payment dates	April 1, Oct. 1	April 1, Oct. 1	April 1, Oct. 1	March 15, Sept. 15	April 15, Oct. 15
Call premium redemption period (1)	Oct 1, 2014	Oct 1, 2015	April 1, 2016	March 15, 2017	n/a
Make-whole redemption period (2)	Oct 1, 2014	Oct 1, 2015	April 1, 2016	March 15, 2017	Jan 15, 2023
Equity offering redemption period (3)	—	—	April 1, 2014	March 15, 2015	n/a

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

(2) At any time prior to these dates, the Company has the option to redeem all or a portion of its senior notes at the "make-whole" redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

(3) At any time prior to these dates, the Company may redeem up to 35% of the principal amount of its senior notes under certain circumstances with the net cash proceeds from one or more equity offerings at the redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption. The optional redemption period for the 2019 Notes and 2020 Notes using equity offering proceeds expired on October 1, 2012 and October 1, 2013, respectively.

The Company's senior notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures, excluding the indenture governing the 2023 Notes, contain certain restrictions on the Company's ability to incur additional debt, pay dividends on common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of the Company's assets. However, as a result of the increase in credit ratings assigned to the Company's senior unsecured debt and release of credit facility collateral in December 2013 as described above, certain of the restrictive covenants are not currently applicable, including those limiting the Company's ability to incur additional debt, pay dividends, make certain investments, engage in certain affiliate transactions, and sell certain assets, among others. In the event the Company's credit ratings are reduced below BBB- by S&P or Baa3 by Moody's or collateral is reinstated under the credit facility, such covenants would be restored. The indenture governing the 2023 Notes is less restrictive and contains covenants that, among others, limit the Company's ability to create liens securing certain indebtedness and consolidate, merge or transfer certain assets.

The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at December 31, 2013. Two of the Company's subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have insignificant assets with no current value and no operations, fully and unconditionally guarantee the senior notes. The Company's other subsidiary, 20 Broadway Associates LLC, the value of whose assets and operations are minor, does not guarantee the senior notes.

Note payable

In February 2012, 20 Broadway Associates LLC, a 100% owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.0 million is reflected as a current liability under the caption "Current portion of long-term debt" in the consolidated balance sheets at December 31, 2013.

Note 8. Income Taxes

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

	Year ended December 31,		
In thousands	2013	2012	2011
Current income tax provision:			
Federal	$6,193	$9,191	$12,931
State	16	1,326	239
Total current income tax provision	6,209	10,517	13,170
Deferred income tax provision:			
Federal	403,002	383,157	212,406
State	39,619	22,137	32,797
Total deferred income tax provision	442,621	405,294	245,203
Total provision for income taxes	$448,830	$415,811	$258,373

The following table reconciles the provision for income taxes with income tax at the Federal statutory rate for the periods presented:

	Year ended December 31,		
In thousands	2013	2012	2011
Federal income tax provision at statutory rate (35%)	$424,567	$404,319	$240,606
State income tax provision, net of Federal benefit	25,838	15,213	17,684
Other, net	(1,575)	(3,721)	83
Provision for income taxes	$448,830	$415,811	$258,373

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The components of the Company’s deferred tax assets and liabilities as of December 31, 2013 and 2012 are as follows:

	December 31,	
In thousands	2013	2012
Current:		
Deferred tax assets (1)		
Non-cash losses on derivatives	$33,029	$—
Other	2,288	2,413
Total current deferred tax assets	35,317	2,413
Deferred tax liabilities		
Other	645	2,048
Total current deferred tax liabilities	645	2,048
Net current deferred tax assets	34,672	365
Noncurrent:		
Deferred tax assets		
Net operating loss carryforwards	41,791	40,441
Non-cash losses on derivatives	2,975	—
Alternative minimum tax carryforwards	38,689	27,380
Other	20,220	11,576
Total noncurrent deferred tax assets	103,675	79,397
Deferred tax liabilities		
Property and equipment	1,840,331	1,330,551
Other	156	11,422
Total noncurrent deferred tax liabilities	1,840,487	1,341,973
Net noncurrent deferred tax liabilities	1,736,812	1,262,576
Net deferred tax liabilities (2)	$1,702,140	$1,262,211

(1) Deferred and prepaid taxes on the consolidated balance sheets contain receivables of $9.7 million for prepaid income taxes at December 31, 2013, with no such prepayments at December 31, 2012.

(2) In addition to the 2012 provision for income taxes of $415.8 million, activity during 2012 includes an increase to deferred tax liabilities of $56.6 million related to the acquisition of assets from Wheatland Oil Inc. (see Note 14) and a decrease of $15.6 million related to the excess tax benefits of stock-based compensation.

As of December 31, 2013, the Company had state net operating loss carryforwards totaling $1.0 billion which will expire beginning in 2017. The carryforwards have expiration periods that vary according to state jurisdiction. The Company has alternative minimum tax credit carryforwards of $39 million that have no expiration date. Any available statutory depletion carryforwards will be recognized when realized. The Company files income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal, state and local income tax examinations by tax authorities for years prior to 2010.

Note 9. Lease Commitments

The Company’s operating lease obligations primarily represent leases for office equipment, communication towers and tanks for storage of hydraulic fracturing fluids. Lease payments associated with operating leases for the years ended December 31, 2013, 2012 and 2011 were $3.0 million, $2.2 million and $1.7 million, respectively, a portion of which was capitalized and/or billed to other interest owners. At December 31, 2013 the minimum future rental commitments under operating leases having lease terms in excess of one year are as follows:

	Total amount
In these years	In thousands
2014	$1,954
2015	432

2016	346
2017	255
2018	151
Thereafter	182
Total obligations	$3,320

Note 10. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of December 31, 2013. The commitments under these arrangements are not recorded in the accompanying consolidated balance sheets.

Drilling commitments – As of December 31, 2013, the Company had drilling rig contracts with various terms extending through January 2016. These contracts were entered into in the ordinary course of business to ensure rig availability to allow the Company to execute its business objectives in its key strategic plays. Future commitments as of December 31, 2013 total approximately $110 million, of which $83 million is expected to be incurred in 2014, $26 million in 2015, and less than $1 million in 2016.

Fracturing and well stimulation service agreement – The Company has 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 the Company’s properties in North Dakota and Montana. The agreement, which expires in September 2014, requires the Company 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. The agreement also stipulates the Company will bear the cost of certain products and materials used. Future commitments remaining as of December 31, 2013 amount to approximately $16 million, which is expected to be incurred through September 2014.

Pipeline transportation commitments – The Company has entered into firm transportation commitments to guarantee pipeline access capacity on operational crude oil pipelines in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The commitments, which have 5-year terms extending as far as November 2017, require the Company to pay varying per-barrel transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of December 31, 2013 under the operational crude oil pipeline transportation arrangements amount to approximately $43 million, of which $14 million is expected to be incurred in 2014, $14 million in 2015, $10 million in 2016, and $5 million in 2017.

The Company has also entered into a commitment to guarantee pipeline access capacity on an operational natural gas pipeline system to move a portion of its North region natural gas production to market. The commitment, which has a 10-year term ending in October 2023, requires the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments under the arrangement amount to approximately $24 million as of December 31, 2013, which is expected to be incurred ratably over its 10-year term.

Further, the Company is a party to additional 5-year firm transportation commitments for future crude oil pipeline projects being constructed or considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require significant additional construction efforts by our counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.0 billion at December 31, 2013, which includes approximately $96 million subject to a joint tariff arrangement between an unaffiliated party and an affiliate controlled by the Company's principal shareholder as discussed in Note 11. Related Party Transactions. These commitments represent aggregate transportation charges expected to be incurred over the 5-year terms of the arrangements assuming the proposed pipeline projects are completed and become operational. The exact timing of the commencement of pipeline operations is not known due to uncertainties involving matters such as regulatory approvals, resolution of legal and environmental disputes, construction progress, and the ultimate probability of pipeline completion. Accordingly, the timing of the Company's obligations under these non-operational arrangements 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. Although timing is uncertain, operators have indicated that certain pipeline projects may become operational in the fourth quarter of 2014, which would obligate the Company for transportation charges totaling $36 million in the 2014 fourth quarter, $143 million per year in years 2015 through 2018, and $106 million in 2019 associated with those projects.

Rail transportation commitments – The Company has entered into firm transportation commitments to guarantee capacity on rail transportation facilities in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The rail commitments have various terms extending through June 2014 and require the Company to pay varying per-barrel transportation charges regardless of the amount of rail capacity used. Future commitments remaining as of December 31, 2013 under the rail transportation arrangements amount to approximately $10 million, which is expected to be incurred through June 2014.

The Company's pipeline and rail transportation commitments are for production primarily in the North region where the Company allocates a significant portion of its capital expenditures. The Company is not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Cost sharing commitment – The Company has 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 the Company operates. This arrangement extends through January 2016 and requires the Company to make scheduled periodic payments based on the projected total cost of the project and the progress of construction. Future commitments under the arrangement as of December 31, 2013 total approximately $25 million, of which $15 million is expected to be incurred in 2014, $8 million in 2015, and $2 million in 2016.

Litigation – 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. 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. As of December 31, 2013 and 2012, the Company has recorded a liability on the consolidated balance sheets under the caption "Other noncurrent liabilities" of $1.7 million and $2.4 million, respectively, for various matters, none of which are believed to be individually significant.

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

Note 11. Related Party Transactions

The Company sells a portion of its natural gas production to affiliates. For the years ended December 31, 2013, 2012, and 2011, these sales amounted to $105.1 million, $61.7 million, and $53.5 million, respectively, and are included in the caption "Crude oil and natural gas sales to affiliates" in the consolidated statements of income. At December 31, 2013 and 2012, $12.7 million

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and $11.7 million, respectively, was due to the Company from these affiliates, which is included in the caption “Receivables—Affiliated parties” in the consolidated balance sheets.

The Company engages in crude oil trades with an affiliate from time to time to obtain space on pipeline systems in the Company's operating areas. For the years ended December 31, 2012, and 2011, crude oil sales to the affiliate totaled 21,000 barrels and 435,000 barrels, respectively, generating sales proceeds of $1.9 million and $41.7 million, respectively. There were no crude oil sales to the affiliate in 2013. In 2013 and 2012, the Company purchased 30,000 barrels and 2,000 barrels, respectively, from the affiliate for $3.0 million and $0.2 million, respectively, with no purchases being made from the affiliate in 2011. The Company incurred $2.2 million, $2.7 million, and $1.4 million in transportation and gathering expenses in 2013, 2012, and 2011, respectively, associated with these transactions. At both December 31, 2013 and 2012, $0.2 million was due from the Company to the affiliate associated with these transactions, which is included in the caption “Payables to affiliated parties” in the consolidated balance sheets.

The Company contracts for field services such as compression and drilling rig services and purchases residue fuel gas and reclaimed crude oil from certain affiliates. The Company capitalized costs of $5.7 million, $5.0 million and $4.1 million in 2013, 2012, and 2011, respectively, associated with drilling rig services provided by an affiliate. Production and other expenses attributable to these affiliate transactions were $1.4 million, $2.0 million and $4.6 million for the years ended December 31, 2013, 2012, and 2011, respectively. The total amount paid to these affiliates, a portion of which was billed to other interest owners, was $48.5 million, $32.7 million and $30.8 million for the years ended December 31, 2013, 2012, and 2011, respectively. Under a contract for natural gas sales to an affiliate, the Company incurred gathering and treatment fees which amounted to $4.7 million in 2013, $4.7 million in 2012 and $4.6 million in 2011. At December 31, 2013 and 2012, $5.1 million and $5.6 million, respectively, was due to these affiliates related to these transactions, which is included in the caption “Payables to affiliated parties” in the consolidated balance sheets.

Certain officers and other key employees of the Company own or control entities that own working and royalty interests in wells operated by the Company. The Company paid revenues to these affiliates, including royalties, of $2.3 million, $38.3 million, and $46.8 million and received payments from these affiliates of $1.3 million, $38.5 million, and $67.5 million during the years ended December 31, 2013, 2012, and 2011, respectively, relating to the operations of the respective properties. The Company also paid to these affiliates $277,000 in 2012 and $4,900 in 2011 for their share of proceeds from undeveloped leasehold sales, with no such payments in 2013. At December 31, 2013 and 2012, $0.4 million and $0.7 million was due from these affiliates and approximately $0.2 million and $0.3 million was due to these affiliates, respectively, relating to these transactions.

Prior to July 2012, the Company leased office space under an operating lease from an entity owned by the Company’s principal shareholder. Rents paid associated with the leases totaled approximately $0.7 million and $1.0 million for the years ended December 31, 2012 and 2011, respectively.

The Company allows certain affiliates to use its corporate aircraft and crews and has used the aircraft and crews of those same affiliates from time to time in order to facilitate efficient transportation of Company personnel. The rates charged between the parties vary by type of aircraft used. For usage during 2013, 2012, and 2011, the Company charged affiliates approximately $55,000, $112,000, and $235,000, respectively, for use of its corporate aircraft, crews and fuel and training costs and received $379,000 from the affiliate in 2013 for certain current and prior year charges. The Company was charged $51,000, $102,000, and $88,000, respectively, by affiliates for use of their aircraft and crews during 2013, 2012, and 2011 and paid $238,000 to the affiliates in 2013 for certain current and prior year charges.

In September 2012, the Company entered into 5-year firm transportation commitments under a joint tariff arrangement to guarantee pipeline access capacity totaling 10,000 barrels of crude oil per day on pipeline projects being developed by an affiliated party and an unaffiliated party that are not yet operational. The pipeline projects require additional construction efforts by those parties before being completed. The commitments require the Company to pay joint tariff transportation charges of $5.25 per barrel regardless of the amount of pipeline capacity used, which will be allocated between the affiliated party and unaffiliated party. Future commitments under the joint tariff arrangement, a portion of which will be allocated to the affiliate, total approximately $96 million at December 31, 2013, representing aggregate joint tariff transportation charges expected to be incurred over the 5-year term assuming the pipeline projects are completed and become operational. The commitments under this arrangement are not recorded in the accompanying consolidated balance sheets.

In August 2012, the Company acquired the assets of Wheatland Oil Inc. Wheatland is owned 75% by the Revocable Inter Vivos Trust of Harold G. Hamm, a trust of which Harold G. Hamm, the Company's Chief Executive Officer, Chairman of the Board and principal shareholder is the trustee and sole beneficiary, and 25% by the Company's Vice Chairman of Strategic Growth Initiatives, Jeffrey B. Hume. See Note 14. Property Transaction with Related Party for further discussion.

Note 12. Stock-Based Compensation

The Company has granted stock options to employees pursuant to the Continental Resources, Inc. 2000 Stock Option Plan ("2000 Plan") and restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2005 Long-Term Incentive Plan ("2005 Plan") and 2013 Long-Term Incentive Plan ("2013 Plan") as discussed below. The Company's associated compensation expense, which is included in the caption "General and administrative expenses" in the consolidated statements of income, is reflected in the table below for the periods presented.

	Year ended December 31,		
In thousands	2013	2012	2011
Non-cash equity compensation	$39,890	$29,057	$16,572

Stock options

Effective October 1, 2000, the Company adopted the 2000 Plan and granted stock options to certain eligible employees. On November 10, 2005, the 2000 Plan was terminated. As of March 31, 2012, all options issued under the 2000 Plan had been exercised or expired. The following table summarizes stock option activity under the 2000 Plan for the periods presented:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding at December 31, 2010	104,970	$0.71	104,970	$0.71
Exercised	(18,470)	$0.71		
Outstanding at December 31, 2011	86,500	$0.71	86,500	$0.71
Exercised	(86,500)	$0.71		
Outstanding at December 31, 2012	—	—	—	—

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. The total intrinsic value of options exercised during the years ended December 31, 2012 and 2011 was $7.6 million and $1.1 million, respectively.

Restricted stock

In May 2013, the Company's shareholders, upon recommendation by the Board of Directors, approved the adoption of the Company's 2013 Plan. The 2013 Plan is a broad-based incentive plan that allows the Company to use, if desired, a variety of equity compensation alternatives in structuring compensation arrangements for the Company's officers, directors and select employees. Effective May 23, 2013, the 2013 Plan replaced the Company's 2005 Plan as the instrument used to grant long-term incentive awards and no further awards will be granted under the 2005 Plan. However, restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms.

The maximum number of shares of common stock available for issuance under the 2013 Plan is 9,840,036 shares, which includes (i) 7,500,000 new shares authorized under the 2013 Plan, (ii) 1,840,036 shares that remained available for issuance under the 2005 Plan as of March 27, 2013 that have been transferred from the 2005 Plan to the 2013 Plan, and (iii) up to 500,000 shares available for issuance under the 2013 Plan to the extent such shares are forfeited or withheld for payment of income taxes related to existing awards outstanding under the 2005 Plan. As of December 31, 2013, the Company had a maximum of 9,813,989 shares of restricted stock available to grant to officers, directors and select employees under the 2013 Plan.

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

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A summary of changes in non-vested restricted shares from December 31, 2010 to December 31, 2013 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2010	1,108,077	$35.72
Granted	491,315	63.59
Vested	(359,601)	29.95
Forfeited	(41,447)	41.93
Non-vested restricted shares at December 31, 2011	1,198,344	$48.66
Granted	916,028	73.46
Vested	(444,723)	45.25
Forfeited	(40,187)	59.05
Non-vested restricted shares at December 31, 2012	1,629,462	$63.28
Granted	261,259	97.95
Vested	(464,809)	47.30
Forfeited	(68,756)	71.91
Non-vested restricted shares at December 31, 2013	1,357,156	$74.99

The grant date fair value of restricted stock represents the closing market price of the Company’s common stock on the date of grant. Compensation expense for a restricted stock grant is a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company’s restricted stock. The fair value of restricted stock that vested during 2013, 2012 and 2011 at the vesting date was $49.4 million, $33.0 million and $19.9 million, respectively. As of December 31, 2013, there was approximately $55 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized ratably over a weighted average period of 1.5 years.

Note 13. Property Acquisitions and Dispositions

Acquisitions

In December 2012, the Company acquired certain producing and undeveloped properties in the Bakken play of North Dakota from a third party for $663.3 million, of which $477.1 million was allocated to producing properties. In the transaction, the Company acquired interests in approximately 119,000 net acres as well as producing properties with production of approximately 6,500 net barrels of oil equivalent per day.

In August 2012, the Company acquired the assets of Wheatland Oil Inc. through the issuance of shares of the Company’s common stock. See Note 14. Property Transaction with Related Party for further discussion.

In February 2012, the Company acquired certain producing and undeveloped properties in the Bakken play of North Dakota from a third party for $276 million, of which $51.7 million was allocated to producing properties. In the transaction, the Company acquired interests in approximately 23,100 net acres as well as producing properties with production of approximately 1,000 net barrels of oil equivalent per day.

Dispositions

In December 2012, the Company sold its producing crude oil and natural gas properties and supporting assets in its East region to a third party for $126.4 million. In connection with the transaction, the Company recognized a pre-tax gain of $68.0 million, which included the effect of removing $8.3 million of asset retirement obligations for the disposed properties previously recognized by the Company that were assumed by the buyer. The transaction excluded a portion of the Company’s non-producing leasehold acreage in the East region, which was retained by the Company for future exploration and development opportunities. The transaction also allowed for the Company to retain an overriding royalty interest in certain of the disposed properties as well as rights to drill in potential unproven deeper formations that may exist below the disposed properties. The disposed properties represented an immaterial portion of the Company's total proved reserves, production, and revenues.

In June 2012, the Company assigned certain non-strategic leaseholds and producing properties located in Oklahoma to a third party for $15.9 million and recognized a pre-tax gain on the transaction of $15.9 million, which included the effect of removing $0.6 million of asset retirement obligations for the disposed properties previously recognized by the Company that were assumed by the buyer. The disposed properties represented an immaterial portion of the Company's total proved reserves, production, and revenues.

In February 2012, the Company assigned certain non-strategic leaseholds and producing properties located in Wyoming to a third party for $84.4 million. In connection with the transaction, the Company recognized a pre-tax gain of $50.1 million, which included the effect of removing $11.1 million of asset retirement obligations for the disposed properties previously recognized by the Company that were assumed by the buyer. The disposed properties represented an immaterial portion of the Company's total proved reserves, production, and revenues.

During 2011, the Company assigned certain non-strategic properties in Michigan, North Dakota, and Montana to third parties for total proceeds of $30.2 million. In connection with the transactions, the Company recognized pre-tax gains totaling $21.4 million. Substantially all of the properties disposed of in 2011 consisted of undeveloped leasehold acreage with no proved reserves and no production or revenues.

The gains on the above dispositions are included in the caption "Gain on sale of assets, net" in the consolidated statements of income.

Note 14. Property Transaction with Related Party

In March 2012, the Company entered into a Reorganization and Purchase and Sale Agreement (the "Agreement") with Wheatland Oil Inc. ("Wheatland") and the shareholders of Wheatland. Wheatland is owned 75% by the Revocable Inter Vivos Trust of Harold G. Hamm, a trust of which Harold G. Hamm, the Company's Chief Executive Officer, Chairman of the Board and principal shareholder is the trustee and sole beneficiary, and 25% by the Company's Vice Chairman of Strategic Growth Initiatives, Jeffrey B. Hume. The Agreement provided for the acquisition by the Company, through the issuance of shares of the Company's common stock, of all of Wheatland's right, title and interest in and to certain crude oil and natural gas properties and related assets, in which the Company also owned an interest, in the states of Mississippi, Montana, North Dakota and Oklahoma and the assumption of certain liabilities related thereto.

The Wheatland transaction was consummated and closed on August 13, 2012, with an effective date of January 1, 2012. At closing, the Company issued an aggregate of approximately 3.9 million shares of its common stock, par value $0.01 per share, to the shareholders of Wheatland in accordance with the terms of the Agreement. The fair value of the consideration transferred by the Company at closing was approximately $279 million. In 2013, Wheatland paid the Company approximately $0.5 million upon final settlement of purchase price adjustments under the terms of the Agreement.

For accounting purposes, the acquisition represented a transaction between entities under common control as Mr. Hamm is the controlling shareholder of both the Company and Wheatland. Accordingly, the Company recorded the assets acquired and liabilities assumed at Wheatland's carrying amount. The net book basis of Wheatland's assets was approximately $82 million, primarily representing $177 million for acquired crude oil and natural gas properties partially offset by $38 million of joint interest obligations assumed, $0.6 million of asset retirement obligations assumed and $57 million of deferred income tax liabilities recognized. For the year ended December 31, 2012, the acquired Wheatland properties comprised approximately 484 MBoe of the Company's crude oil and natural gas production and approximately $38 million of its crude oil and natural gas revenues.

Note 15. Crude Oil and Natural Gas Property Information

The following table sets forth the Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2013, 2012 and 2011.

	Year ended December 31,		
In thousands	2013	2012	2011
Crude oil and natural gas sales	$3,606,774	$2,379,433	$1,647,419
Production expenses	(282,197)	(195,440)	(138,236)
Production taxes and other expenses	(332,130)	(228,438)	(144,810)
Exploration expenses	(34,947)	(23,507)	(27,920)
Depreciation, depletion, amortization and accretion	(953,796)	(683,207)	(384,301)
Property impairments	(220,508)	(122,274)	(108,458)
Income taxes	(659,783)	(428,095)	$(321,447)
Results from crude oil and natural gas producing activities	$1,123,413	$698,472	$522,247

Costs incurred in crude oil and natural gas activities

Costs incurred, both capitalized and expensed, in connection with the Company's crude oil and natural gas acquisition, exploration and development activities for the years ended December 31, 2013, 2012 and 2011 are presented below:

	Year ended December 31,		
In thousands	2013	2012	2011
Property Acquisition Costs:			
Proved	$16,604	$738,415	$65,315
Unproved	546,881	745,601	183,247
Total property acquisition costs	563,485	1,484,016	248,562
Exploration Costs	687,767	857,681	734,797
Development Costs	2,549,203	1,975,660	1,178,136
Total	$3,800,455	$4,317,357	$2,161,495

Exploration costs above include asset retirement costs of $1.8 million, $3.3 million and $1.7 million and development costs above include asset retirement costs of $6.0 million, $1.0 million and $3.7 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Aggregate capitalized costs

Aggregate capitalized costs relating to the Company's crude oil and natural gas producing activities and related accumulated depreciation, depletion and amortization as of December 31, 2013 and 2012 are as follows:

	December 31,	
In thousands	2013	2012
Proved crude oil and natural gas properties	$12,423,878	$8,980,505
Unproved crude oil and natural gas properties	1,181,268	1,073,944
Total	13,605,146	10,054,449
Less accumulated depreciation, depletion and amortization	(3,083,180)	(2,090,845)
Net capitalized costs	$10,521,966	$7,963,604

Under the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending determination of whether proved reserves can be attributed to the discovery. When initial drilling operations are complete, management attempts to determine whether the well has discovered crude oil and natural gas reserves and, if so, whether those reserves can be classified as proved reserves. Often, the determination of whether proved reserves can be recorded under SEC guidelines cannot be made when drilling is completed. In those situations where management believes that economically

producible hydrocarbons have not been discovered, the exploratory drilling costs are reflected on the consolidated statements of income as dry hole costs, a component of "Exploration expenses". Where sufficient hydrocarbons have been discovered to justify further exploration or appraisal activities, exploratory drilling costs are deferred under the caption "Net property and equipment" on the consolidated balance sheets pending the outcome of those activities.

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

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

	Year ended December 31,		
In thousands	2013	2012	2011
Balance at January 1	$92,699	$128,123	$92,806
Additions to capitalized exploratory well costs pending determination of proved reserves	548,933	485,530	500,046
Reclassification to proved crude oil and natural gas properties based on the determination of proved reserves	(479,507)	(520,187)	(456,780)
Capitalized exploratory well costs charged to expense	(9,350)	(767)	(7,949)
Balance at December 31	$152,775	$92,699	$128,123
Number of gross wells	67	46	56

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

The table below shows estimates of proved reserves prepared by the Company's internal technical staff and independent external reserve engineers in accordance with SEC definitions. Ryder Scott Company, L.P. ("Ryder Scott") prepared reserve estimates for properties comprising approximately 99%, 99%, and 96% of the Company's discounted future net cash flows (PV-10) as of December 31, 2013, 2012, and 2011, respectively. Properties comprising 99% of proved crude oil reserves and 94% of proved natural gas reserves were evaluated by Ryder Scott as of December 31, 2013. Remaining reserve estimates were prepared by the Company's internal technical staff. All reserves stated herein are located in the United States.

Proved reserves are estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured, and estimates of engineers other than the Company's might differ materially from the estimates set forth herein. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates may differ significantly from the quantities of crude oil and natural gas ultimately recovered.

Reserves at December 31, 2013, 2012 and 2011 were computed using the 12-month unweighted average of the first-day-of-the-month commodity prices as required by SEC rules.

Natural gas imbalance receivables and payables for each of the three years ended December 31, 2013, 2012 and 2011 were not material and have not been included in the reserve estimates.

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

Proved crude oil and natural gas reserves
Changes in proved reserves were as follows for the periods presented:

	Crude Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Proved reserves as of December 31, 2010	224,784	839,568	364,712
Revisions of previous estimates	28,607	(158,219)	2,237
Extensions, discoveries and other additions	87,465	447,098	161,981
Production	(16,469)	(36,671)	(22,581)
Sales of minerals in place	—	—	—
Purchases of minerals in place	1,746	2,056	2,089
Proved reserves as of December 31, 2011	326,133	1,093,832	508,438
Revisions of previous estimates	33,272	(174,736)	4,149
Extensions, discoveries and other additions	166,844	400,848	233,652
Production	(25,070)	(63,875)	(35,716)
Sales of minerals in place	(7,165)	(4,046)	(7,838)
Purchases of minerals in place	67,149	89,061	81,992
Proved reserves as of December 31, 2012	561,163	1,341,084	784,677
Revisions of previous estimates	(55,783)	(241,623)	(96,054)
Extensions, discoveries and other additions	267,009	1,065,870	444,654
Production	(34,989)	(87,730)	(49,610)
Sales of minerals in place	—	—	—
Purchases of minerals in place	388	419	458
Proved reserves as of December 31, 2013	737,788	2,078,020	1,084,125

Revisions of previous estimates. 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.
Upward revisions to crude oil reserves for both of the years ended December 31, 2011 and 2012 were due to better than anticipated production performance, with 2011 revisions also being positively impacted by higher average commodity prices throughout 2011 as compared to 2010. Downward revisions to natural gas reserves for both of the years ended December 31, 2011 and 2012 were due to the removal of proved undeveloped ("PUD") reserves for certain dry gas properties not expected to be developed given the pricing environment for natural gas.
Revisions for the year ended December 31, 2013 primarily represent the removal of PUD reserves resulting from a decision in 2013 to allocate a greater focus of the Company's 5-year growth plan to drilling programs in higher rates-of-return crude oil and liquids-rich natural gas areas of the Bakken and SCOOP while continuing to build on the early success in the Company's development of the Lower Three Forks reservoirs in the Bakken. Another contributing factor is the Company's increased focus 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 to maximize rates of return. These factors contributed to the removal of 42 MMBo and 235 Bcf (81 MMBoe) of PUD reserves in 2013.
Extensions, discoveries and other additions. These are additions to proved reserves resulting from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.
Extensions, discoveries and other additions for each of the three years reflected in the table above were primarily due to increases in proved reserves associated with our successful drilling activity and strong production growth in the Bakken field. Proved reserve additions in the Bakken totaled 227 MMBo and 293 Bcf (276 MMBoe) for the year ended December 31, 2013. Additionally, 2013 extensions and discoveries were significantly impacted by successful

drilling results in the emerging SCOOP play, resulting in 36 MMBo and 730 Bcf (158 MMBoe) of proved reserve additions during the year. Significant progress continued to be made in 2013 in developing and expanding the Company's Bakken and SCOOP assets, both laterally and vertically, through strategic exploration, development, planning and technology.

Sales of minerals in place. These are reductions to proved reserves resulting from the disposition of properties during a period. During the year ended December 31, 2012, the Company disposed of certain non-strategic properties in Oklahoma, Wyoming, and the East region. See Note 13. Property Acquisitions and Dispositions for further discussion of the Company's 2012 dispositions.

Purchases of minerals in place. These are additions to proved reserves resulting from the acquisition of properties during a period. Purchases for the year ended December 31, 2012 primarily reflected the Company's acquisitions of properties in the Bakken play of North Dakota during the year. See Note 13. Property Acquisitions and Dispositions and Note 14. Property Transaction with Related Party for further discussion of the Company's 2012 acquisitions.

The following reserve information sets forth the estimated quantities of proved developed and proved undeveloped crude oil and natural gas reserves of the Company as of December 31, 2013, 2012 and 2011:

	December 31, 2013	2012	2011
Proved Developed Reserves			
Crude oil (MBbl)	278,630	226,870	145,024
Natural Gas (MMcf)	768,969	545,499	361,265
Total (MBoe)	406,792	317,786	205,235
Proved Undeveloped Reserves			
Crude oil (MBbl)	459,158	334,293	181,109
Natural Gas (MMcf)	1,309,051	795,585	732,567
Total (MBoe)	677,333	466,891	303,203
Total Proved Reserves			
Crude oil (MBbl)	737,788	561,163	326,133
Natural Gas (MMcf)	2,078,020	1,341,084	1,093,832
Total (MBoe)	1,084,125	784,677	508,438

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

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

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

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves as of December 31, 2013, 2012 and 2011.

	December 31,		
In thousands	2013	2012	2011
Future cash inflows	$78,646,274	$54,362,574	$35,042,916
Future production costs	(21,333,460)	(13,103,469)	(7,495,552)
Future development and abandonment costs	(10,250,789)	(8,295,130)	(5,073,043)
Future income taxes	(12,447,127)	(8,500,766)	(5,956,615)
Future net cash flows	34,614,898	24,463,209	16,517,706
10% annual discount for estimated timing of cash flows	(18,319,131)	(13,282,852)	(9,012,350)
Standardized measure of discounted future net cash flows	$16,295,767	$11,180,357	$7,505,356

The weighted average crude oil price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $91.50, $86.56, and $88.71 per barrel at December 31, 2013, 2012 and 2011, respectively. The weighted average natural gas price (adjusted for location and quality differentials) utilized in the computation of future cash inflows was $5.36, $4.31, and $5.59 per Mcf at December 31, 2013, 2012 and 2011, respectively. Future cash flows are reduced by estimated future costs to develop and produce the proved reserves, as well as certain abandonment costs, based on year-end cost estimates assuming continuation of existing economic conditions. The expected tax benefits to be realized from the utilization of net operating loss carryforwards and tax credits are used in the computation of future income tax cash flows.

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

	December 31,		
In thousands	2013	2012	2011
Standardized measure of discounted future net cash flows at January 1	$11,180,357	$7,505,356	$3,785,322
Extensions, discoveries and improved recoveries, less related costs	6,613,665	3,724,136	2,276,355
Revisions of previous quantity estimates	(1,765,300)	254,493	133,990
Changes in estimated future development and abandonment costs	1,942,585	(298,148)	(70,219)
Purchases (sales) of minerals in place, net	12,012	1,171,047	56,246
Net change in prices and production costs	263,541	(530,515)	1,855,532
Accretion of discount	1,118,036	750,536	378,532
Sales of crude oil and natural gas produced, net of production costs	(2,992,447)	(1,955,555)	(1,364,373)
Development costs incurred during the period	1,210,223	1,095,156	528,737
Change in timing of estimated future production and other	464,111	(102,519)	773,279
Change in income taxes	(1,751,016)	(433,630)	(848,045)
Net change	5,115,410	3,675,001	3,720,034
Standardized measure of discounted future net cash flows at December 31	$16,295,767	$11,180,357	$7,505,356

Note 17. Quarterly Financial Data (Unaudited)

The Company's unaudited quarterly financial data for 2013 and 2012 is summarized below.

	Quarter ended			
In thousands, except per share data	March 31	June 30	September 30	December 31
2013				
Total revenues (1)	$710,229	$1,100,752	$823,835	$820,334
Gain (loss) on derivative instruments, net (1)	$(84,831)	$199,056	$(203,774)	$(102,202)
Income from operations	$270,146	$573,872	$328,043	$273,706
Net income	$140,627	$323,270	$167,498	$132,824
Net income per share:				
Basic	$0.76	$1.76	$0.91	$0.72
Diluted	$0.76	$1.75	$0.91	$0.72
2012				
Total revenues (1)	$395,100	$1,004,719	$483,729	$688,972
Gain (loss) on derivative instruments, net (1)	$(169,057)	$471,728	$(158,294)	$9,639
Income from operations	$135,591	$686,474	$105,522	$365,220
Net income	$69,094	$405,684	$44,096	$220,511
Net income per share:				
Basic	$0.38	$2.26	$0.24	$1.20
Diluted	$0.38	$2.25	$0.24	$1.19

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

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

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

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2013 to ensure that information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors during the fourth quarter of 2013 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our Company's management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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

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

Based on our evaluation under the framework in Internal Control—Integrated Framework (1992), the management of our Company concluded that our internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report that follows.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Continental Resources, Inc.

We have audited the internal control over financial reporting of Continental Resources, Inc. (an Oklahoma corporation) and Subsidiaries (the "Company") as of December 31, 2013, based on criteria established in the 1992 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2013, and our report dated February 26, 2014 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 26, 2014

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held in May 2014 (the “Annual Meeting”) and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(1) Financial Statements

The consolidated financial statements of Continental Resources, Inc. and Subsidiaries and the Report of Independent Registered Public Accounting Firm are included in Part II, Item 8 of this report beginning on page 67.

(2) Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes thereto.

(3) Index to Exhibits

The exhibits required to be filed or furnished pursuant to Item 601 of Regulation S-K are set forth below.

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed February 24, 2012 as Exhibit 3.1 to the Company's 2011 Form 10-K (Commission File No. 001-32886) and incorporated herein by reference.
3.2	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 6, 2012 and incorporated herein by reference.
4.1	Registration Rights Agreement dated as of May 18, 2007 by and among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust filed February 24, 2012 as Exhibit 4.1 to the Company's 2011 Form 10-K (Commission File No. 001-32886) and incorporated herein by reference.
4.2	Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
4.3	Indenture dated as of September 23, 2009 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust FSB, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed September 24, 2009 and incorporated herein by reference.
4.4	Indenture dated as of April 5, 2010 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust FSB, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed April 7, 2010 and incorporated herein by reference.
4.5	Indenture dated as of September 16, 2010 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust FSB, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed September 17, 2010 and incorporated herein by reference.
4.6	Indenture dated as of March 8, 2012 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed March 8, 2012 and incorporated herein by reference.
4.7	Indenture dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as

	Exhibit 4.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-32886) filed April 11, 2013 and incorporated herein by reference.
4.8	Registration Rights Agreement dated as of August 13, 2012 among Continental Resources, Inc., the Revocable Inter Vivos Trust of Harold G. Hamm, and Jeffrey B. Hume filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-32886) filed August 17, 2012 and incorporated herein by reference.
10.1†	Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006 filed as Exhibit 10.9 to the Company’s Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.2†	Form of Restricted Stock Award Agreement filed as Exhibit 10.10 to the Company’s Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.

10.3†	Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company’s Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.4†	Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company’s Registration Statement on Form S-1 (Commission File No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
10.5	Crude oil transportation agreement between Banner Pipeline Company, L.L.C., a wholly owned subsidiary of Continental Resources, Inc. and Banner Transportation Company dated July 11, 2007 filed February 24, 2012 as Exhibit 10.8 to the Company’s 2011 Form 10-K (Commission File No. 001-32886) and incorporated herein by reference.
10.6	Seventh Amended and Restated Credit Agreement dated June 30, 2010 among Continental Resources, Inc. as borrower, Union Bank, N.A. as administrative agent, as issuing lender and as swing line lender, and the other lenders party thereto, filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-32886) filed July 7, 2010 and incorporated herein by reference.
10.7	Amendment No. 1 dated July 26, 2012 to the Seventh Amended and Restated Credit Agreement dated June 30, 2010, among Continental Resources, Inc., as borrower, Banner Pipeline Company, L.L.C., as guarantor, Union Bank, N.A., as administrative agent and issuing lender, and the other lenders party thereto, filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-32886) filed August 1, 2012 and incorporated herein by reference.
10.8†	First Amendment to the Continental Resources, Inc. 2005 Long-Term Incentive Plan filed February 28, 2013 as Exhibit 10.2 to the Company’s 2012 Form 10-K (Commission File No. 001-32886) and incorporated herein by reference.
10.9	Amendment No. 2 dated April 3, 2013 to the Seventh Amended and Restated Credit Agreement dated June 30, 2010, among Continental Resources, Inc., as borrower, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC as guarantors, Union Bank, N.A., as administrative agent and issuing lender, and the other lenders party thereto, filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-32886) filed April 5, 2013 and incorporated herein by reference.
10.10†	Continental Resources, Inc. 2013 Long-Term Incentive Plan included as Appendix A to the Company's Definitive Proxy Statement on Schedule 14A (Commission File No. 001-32886) filed April 10, 2013 and incorporated herein by reference.
10.11†	Description of cash bonus plan adopted on February 22, 2013 filed as Exhibit 10.1 to the Company's Form 10-Q for the quarter ended March 31, 2013 (Commission File No. 001-32886) filed May 8, 2013 and incorporated herein by reference.
10.12†	Form of Employee Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 24, 2013 and incorporated herein by reference.
10.13†	

	Form of Non-Employee Director Restricted Stock Award Agreement under the Continental Resources, Inc. 2013 Long-Term Incentive Plan filed as Exhibit 10.3 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 24, 2013 and incorporated herein by reference.
10.14†	Summary of Non-Employee Director Compensation Approved as of May 23, 2013 to be effective July 1, 2013 filed as Exhibit 10.6 to the Company's Form 10-Q for the quarter ended June 30, 2013 (Commission File No. 001-32886) filed August 8, 2013 and incorporated herein by reference.
10.15†	Continental Resources, Inc. Deferred Compensation Plan filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed September 26, 2013 and incorporated herein by reference.
10.16	Amendment No. 4 and Consent dated December 11, 2013 to the Seventh Amended and Restated Credit Agreement dated June 30, 2010, among Continental Resources, Inc., as borrower, Banner Pipeline Company LLC, and CLR Asset Holdings, LLC as guarantors, Union Bank, N.A., as administrative agent and issuing lender, and the other lenders party thereto, filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed December 12, 2013 and incorporated herein by reference.
21*	Subsidiaries of Continental Resources, Inc.

23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241)
32**	Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)
99*	Report of Ryder Scott Company, L.P., Independent Petroleum Engineers and Geologists
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

** Furnished herewith

† Management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Continental Resources, Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONTINENTAL RESOURCES, INC.

By:	/S/ HAROLD G. HAMM
Name:	Harold G. Hamm
Title:	Chairman of the Board and Chief Executive Officer
Date:	February 26, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Continental Resources, Inc. and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ HAROLD G. HAMM Harold G. Hamm	Chairman of the Board and Chief Executive Officer (principal executive officer)	February 26, 2014
/s/ JOHN D. HART John D. Hart	Senior Vice President, Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 26, 2014
/s/ DAVID L. BOREN David L. Boren	Director	February 26, 2014
/s/ ROBERT J. GRANT Robert J. Grant	Director	February 26, 2014
/s/ LON MCCAIN Lon McCain	Director	February 26, 2014
/s/ JOHN T. MCNABB II John T. McNabb II	Director	February 26, 2014
/s/ MARK E. MONROE Mark E. Monroe	Director	February 26, 2014
/s/ EDWARD T. SCHAFER Edward T. Schafer	Director	February 26, 2014