Bonanza Creek Energy, Inc.
Form 10-K
February 27, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10 K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 001 35371

Bonanza Creek Energy, Inc.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware | 61 1630631 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 410 17th Street, Suite 1400 Denver, Colorado | 80202 |
| (Address of principal executive offices) | (Zip Code) |

(720) 440 6100

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

| | |
|---|---|
| (Title of Class) | (Name of Exchange) |
| Common Stock, par value $0.001 per share | New York Stock Exchange |

Securities Registered Pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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

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 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 No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S K 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 | 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

The aggregate market value of the registrant's voting and non voting common equity held by non affiliates on June 30, 2014, based upon the closing price of $57.19 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $2,310,572,708. Excludes approximately 242,931 shares of the registrant's common stock held by executive officers, directors and stockholders that the registrant has concluded, solely for the purpose of the foregoing calculation, were affiliates of the registrant.

Number of shares of registrant's common stock outstanding as of February 24, 2015: 49,335,032

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2015 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2014, are incorporated by reference into Part III of this report for the year ended December 31, 2014.

BONANZA CREEK ENERGY, INC.

FORM 10 K

FOR THE YEAR ENDED DECEMBER 31, 2014

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Information Regarding Forward Looking Statements

This Annual Report on Form 10 K contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historic fact, that are forward looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. When used in this Annual Report on Form 10 K, the words “could,” “believe,” “anticipate,” “intend “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project,” “plan” “will,” and similar expressions are intended t forward looking statements, although not all forward looking statements contain such identifying words.

Forward looking statements include statements related to, among other things:

- reserves estimates;
- estimated sales volumes for 2015;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- ability to modify future capital expenditures;
- the Wattenberg Field being a premier oil and resource play in the United States;
- ability to increase sales volumes while lowering costs;
- compliance with debt covenants;
- ability to satisfy obligations related to ongoing operations;
- compliance with government regulations;
- adequacy of gathering systems and continuous improvement of such gathering systems;
- impact from the lack of available gathering systems and processing facilities in certain areas;
- natural gas, oil and natural gas liquid prices and factors affecting the volatility of such prices;
- impact of lower commodity prices;
- the ability to use derivative instruments to manage commodity price risk and ability to use such instruments in the future;
- plans to drill or participate in wells including the intent to focus in specific areas or formations;
- loss of any purchaser of our products;
- our estimated revenues and losses;
- the timing and success of specific projects;
- our implementation of long reach laterals in the Wattenberg Field;

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· our use of multi-well pads to develop the Niobrara and Codell formations;
· intention to continue to optimize enhanced completion techniques and well design changes;
· intentions with respect to working interest percentages;
· management and technical team;
· outcomes and effects of litigation, claims and disputes;
· our business strategy;
· expectation that the Niobrara B and C benches and the Codell formation will be the primary sources of future production growth;
· our ability to replace oil and natural gas reserves;
· impact of recently issued accounting pronouncements;
· impact of the loss a single customer;
timing and ability to meet certain volume commitments related to purchase and transportation agreements;

the impact of customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes and other industry-related constraints;

· our financial position;
· our cash flow and liquidity;
· the adequacy of our insurance;
· our ability to leverage current infrastructure and our operational expertise to integrate and develop the Wattenberg Field Acquisition;
· intention to use the net proceeds of public offering of common stock on February 6, 2015 to repay all of the outstanding borrowings under the revolving credit facility and general corporate purposes; and
· other statements concerning our operations, economic performance and financial condition.

We have based these forward looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. The actual results or developments anticipated by these forward looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences. Actual results could differ materially from those expressed or implied in the forward looking statements.

Factors that could cause actual results to differ materially include, but are not limited to, the following:

· the risk factors discussed in Part I, Item 1A of this Annual Report on Form 10 K;

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- declines or volatility in the prices we receive for our oil, natural gas liquids and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- ability of our customers to meet their obligations to us;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves and, in particular, probable and possible resources;
- the possibility that the industry may be subject to future local, state, and federal regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- seasonal weather conditions and lease stipulations;
- drilling and operating risks, including the risks associated with the employment of horizontal drilling techniques;
- our ability to acquire adequate supplies of water for drilling and completion operations;
- availability of oilfield equipment, services and personnel;
- exploration and development risks;
- competition in the oil and natural gas industry;
- management's ability to execute our plans to meet our goals;
- risks related to our derivative instruments;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;
- access to adequate gathering systems and pipeline take away capacity to provide adequate infrastructure for the products of our drilling program;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- costs and other risks associated with perfecting title for mineral rights in some of our properties;
- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and

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- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations or pricing.

All forward looking statements speak only as of the date of this Annual Report on Form 10 K. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward looking statements we make in this Annual Report on Form 10 K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Annual Report on Form 10 K. These cautionary statements qualify all forward looking statements attributable to us or persons acting on our behalf.

GLOSSARY OF OIL AND NATURAL GAS TERMS

We have included below the definitions for certain terms used in this Annual Report on Form 10 K:

"3 D seismic data" Geophysical data that depict the subsurface strata in three dimensions. 3 D seismic data typically provide a more detailed and accurate interpretation of the subsurface strata than 2 D, or two dimensional, seismic data.

"Analogous reservoir" Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

"Bbl" One stock tank barrel, or 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" One stock tank barrel of oil equivalent, calculated by converting natural gas and natural gas liquids volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

"British thermal unit" or "BTU" The heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"Basin" A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"Completion" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Condensate" A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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

“Development costs” Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves; (ii) drill and equip development wells, development type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly; (iii) acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

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

“Differential” The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead priced received.

“Deterministic method” The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

“Dry hole” Exploratory or development well that does not produce oil or gas in commercial quantities.

“Economically producible” The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

“Environmental assessment” A study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

“ERISA” Employee Retirement Income Security Act of 1974.

“Estimated ultimate recovery (EUR)” Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

“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 oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

“Extension well” A well drilled to extend the limits of a known reservoir.

“Field” An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

“Finding and development costs” Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves, during the same period.

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“Formation” A layer of rock which has distinct characteristics that differ from nearby rock.

“GAAP” Generally accepted accounting principles in the United States.

“HH” Henry Hub index.

“Horizontal drilling” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

‘‘Hydraulic fracturing” The process of injecting water, proppant and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

“LIBOR” London interbank offered rate.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBoe” One thousand Boe.

“Mcf” One thousand cubic feet.

“MMBoe” One million Boe.

“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet.

“Net acres” The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

“Net production” Production that is owned by the registrant and produced to its interest, less royalties and production due others.

“Net revenue interest” Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

“Net well” Deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells expressed as whole numbers and fractions of whole numbers.

“NGL” Natural gas liquid.

“NYMEX” The New York Mercantile Exchange.

“Oil and gas producing activities” defined as (i) the search for crude oil, including condensate and natural gas liquids, or natural gas in their natural states and original locations; (ii) the acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties; (iii) the construction, drilling and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as lifting the oil and gas to the surface and gathering, treating and field processing (as in the case of processing gas to extract liquid hydrocarbons); and (iv) extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coal beds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

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“PDNP” Proved developed non-producing reserves.

“PDP” Proved developed producing reserves.

“Percentage-of-proceeds” A processing contract where the processor receives a percentage of the sold outlet stream, dry gas, NGLs or a combination, from the mineral owner in exchange for providing the processing services. In the Mid-Continent region, we are both a producer and, through ownership of gas plants, a processor, our sales volumes include volumes processed through the gas plants directly related to our working interest and volumes for which we are contractually entitled pursuant to the processing of gas from third party interests.

“Play” A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

“Plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

“Pooling” Pooling is a provision in an oil and gas lease that allows the operator to combine the leased property with properties owned by others. (Pooling is also known as unitization.) The separate tracts are joined to form a drilling unit. Ownership shares are issued according to the acreage contributed or by the production capabilities of each producing well for fields in later stages of development.

“Possible reserves” Those additional reserves that are less certain to be recovered than probable reserves.

“Probable reserves” Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

“Production costs” Costs incurred to operated and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are (a) costs of labor to operate the wells and related equipment and facilities; (b) repairs and maintenance; (c) materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities; (d) property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and (e) severance taxes. Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the costs of oil and gas produced along with production (lifting) costs identified above.

“Productive well” A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

“Proppant” Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man made or specially engineered proppants, such as resin coated sand or high strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"Proved developed reserves" Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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“Proved reserves” Those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(a) The area identified by drilling and limited by fluid contacts, if any, and
(b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
(ii) In the absence of data on fluid contracts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher potions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
(b) The project has been approved for development by all necessary parties and entities, including governmental entities.
(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12 month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first day of the month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

“Proved undeveloped reserves” or “PUD” Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedule to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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"PV 10" A non GAAP financial measure that represents inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first day of the month commodity prices (after adjustment for differentials in location and quality) for each of the preceding twelve months. See footnote (2) to the Proved Reserves table in Item 1. "Business" of this Annual Report on Form 10 K for more information.

"Reasonable certainty" If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"Recompletion" The process of re entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reserves" Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"Reserve replacement percentage" The sum of sales of reserves, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.

"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 individual and separate from other reservoirs.

"Resource play" Refers to drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

"Royalty interest" An interest in an oil and natural gas property entitling the owner to a share of oil or gas production free of production costs, but subject to severance taxes (unless the owner is agreement agency).

"Sales volumes" All volumes for which a reporting entity is entitled to proceeds, including production, net to the reporting entity's interest and third party production obtained from percentage-of-proceeds contracts and sold by the reporting entity.

"Service well" A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"Spacing" Regulation concerning the number of wells which can be drilled on a given area of land. Depending on the depth of the reservoir, one well may be allowed on a small area of five acres or on an area up to 640 acres. Typical spacing is 40 acres for oil wells and 640 acres for gas wells. Also referred to as "well spacing."

“Three stream” The separate reporting of NGLs extracted from the natural gas stream and sold as a separate product.

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“Undeveloped acreage” Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

“Undeveloped reserves” Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as “undeveloped oil and gas reserves.”

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

“Workover” Operations on a producing well to restore or increase production.

“WTI” West Texas Intermediate index.

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PART I

Item 1. Business.

When we use the terms "Bonanza Creek," the "Company," "we," "us," or "our" we are referring to Bonanza Creek Energy, Inc and its consolidated subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under Glossary of Oil and Natural Gas Terms above. Throughout this document we make statements that may be classified as "forward looking." Please refer to the Information Regarding Forward Looking Statements section above for an explanation of these types of statements.

Overview

Bonanza Creek is an independent energy company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids rich natural gas in the United States. Our oil and liquids weighted assets are concentrated primarily in the Wattenberg Field in Colorado, which we have designated the Rocky Mountain region, and the Dorcheat Macedonia Field in southern Arkansas, which we have designated the Mid Continent region. In addition, we own and operate oil producing assets in the North Park Basin in Colorado and the McKamie Patton Field in southern Arkansas. The Wattenberg Field is one of the premier oil and gas resource plays in the United States benefiting from a low cost structure and strong production efficiencies. Our management team has extensive experience acquiring and operating oil and gas properties and significant expertise in horizontal drilling and fracture stimulation, which we believe will contribute to the development of our sizable inventory of projects, including those targeting the Niobrara and Codell formations in the Rocky Mountain region and oily Cotton Valley sands in the Mid-Continent region. We operate approximately 98% of our proved reserves with an average working interest of approximately 86% providing us with significant control over the rate of development of our asset base.

We are currently focused on the horizontal development of significant resource potential from the Niobrara and Codell formations in the Wattenberg Field and expect to invest approximately 90% of our 2015 capital budget in this field. The remaining 10% of our 2015 budget is allocated primarily to vertical development of the Dorcheat Macedonia Field in southern Arkansas, targeting oil rich Cotton Valley sands. We believe the location, scale and the contiguous nature of our acreage in both regions will allow the Company to increase sales volumes while lowering costs in our efforts to maximize the value of the resource potential. Our 2015 budget is expected to maintain the Company's 2014 exit rate sales volumes through the full year, achieving approximately 15% annual growth on a year-over-year basis. In 2014, we successfully drilled 162 and completed 159 productive operated wells and participated in drilling 12 and completing 12 productive non operated wells. The resulting production rates achieved by this program increased sales volumes by 45% over the previous year to 23,519 Boe/d of which 70% was crude oil and natural gas liquids ("NGL"). We had 21 operated wells and three non-operated wells in progress as of December 31, 2014. Our sales volumes during the fourth quarter of 2014 were 25,893 Boe/d, a 23% increase over the comparable period in 2013.

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The following tables summarize our estimated proved reserves, PV-10 reserve value, sales volumes, and projected capital spend as of December 31, 2014:

| Estimated Proved Reserves | Crude Oil (MBbls) | Natural Gas (MMcf) | Natural Gas Liquids (MBbls) | Total Proved (MBoe) |
|---|---|---|---|---|
| Developed | | | | |
| Rocky Mountain | 20,593 | 65,282 | — | 31,473 |
| Mid-Continent | 7,750 | 29,212 | 2,199 | 14,818 |
| | 28,343 | 94,494 | 2,199 | 46,291 |
| Undeveloped | | | | |
| Rocky Mountain | 23,556 | 78,715 | — | 36,675 |
| Mid-Continent | 2,860 | 15,342 | 1,154 | 6,571 |
| | 26,416 | 94,057 | 1,154 | 43,246 |
| Total Proved | 54,759 | 188,551 | 3,353 | 89,537 |

| | Estimated Proved Reserves at December 31, 2014(1) | | | | Sales Volumes for the Year Ended December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|---|
| | Total Proved (MBoe) | % of Total | % Proved Developed | PV-10 ($ in MM)(2) | Average Net Daily Sales Volumes (Boe/d) | % of Total | Projected 2015 Capital Expenditures ($ in millions) | Net Proved Undeveloped Drilling Locations as of December 31, 2014 |
| Rocky Mountain | 68,148 | 76 % | 46 % | $ 986.7 | 17,531 | 75 % | $ 380 | 188.8 |
| Mid-Continent(3) | 21,389 | 24 % | 69 % | 353.8 | 5,978 | 25 % | 40 | 71.5 |
| California | — | — % | — % | — | 10 | — % | | — |
| Total | 89,537 | 100 % | 52 % | $ 1,340.5 | 23,519 | 100 % | $ 420 | 260.3 |

(1) Proved reserves and related future net revenue and PV 10 were calculated using prices equal to the twelve month unweighted arithmetic average of the first day of the month commodity prices for each of the preceding twelve months, which were $94.99 per Bbl WTI and $4.35 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $10.71 per Bbl of crude oil and an increase of $0.89 per MMBtu of natural gas.

(2) PV 10 is a non GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the twelve month unweighted arithmetic average of the first day of the month commodity prices, after adjustment for differentials in location and quality, for each of the preceding twelve months. We believe that PV 10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV 10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts and

sophisticated investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre tax measure is valuable in evaluating the Company and our reserves. PV 10 is not intended to represent the current market value of our estimated reserves. PV 10 differs from Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. Please refer to the Reconciliation of PV 10 to Standardized Measure presented several pages below.

(3) Mid-Continent sales volumes were 5,978 Boe/d for 2014, which is comprised of 5,388 Boe/d of production net to our interest and 590 Boe/d sales volumes from our percentage-of-proceeds contracts.

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Our History

Bonanza Creek Energy, Inc. was incorporated on December 2, 2010 pursuant to the laws of the State of Delaware. On December 23, 2010, in connection with an investment from Project Black Bear LP, an entity advised by West Face Capital Inc. ("West Face Capital") and certain clients of Alberta Investment Management Corporation ("AIMCo"), we acquired Bonanza Creek Energy Company, LLC ("BCEC") and Holmes Eastern Company, LLC ("HEC"), which transactions we refer to as our "Corporate Restructuring." We completed the initial public offering of our common stock in December 2011 (our "IPO") pursuant to which 10,000,000 shares of our common stock were sold.

Our Business Strategies

Our primary goal is to increase stockholder value by investing capital in projects that provide attractive rates of return, and increase our sales volumes, proved reserves and cash flow. We intend to accomplish this by focusing on the following key strategies:

- Increase Sales Volumes from Wattenberg Horizontal Opportunities and Develop Additional Resource Potential in Both of our Core Areas. We expect to continue to generate profitable, long term reserve and production growth predominantly through repeatable, lower risk development drilling on our assets, which have multiple resource horizons. We intend to develop the Niobrara and Codell formations by drilling multi-well pads that utilize horizontal drilling and multi-stage fracturing in order to reduce surface use disturbance and to optimize efficiencies related to drilling and completion times, shared use of production facilities and overall resources recovery. We also expect to increase our implementation of long reach laterals (greater than 4,000 feet) to further reduce the number of surface locations needed to develop the Wattenberg Field.
- Maintain High Degree of Operatorship. We currently have and intend to maintain a high working interest in our assets, thereby allowing us to leverage our technical, operating and management skills and control the timing of our capital expenditures.
- Manage Risk Exposure. In order to achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in oil prices, we have entered into and intend in the future to enter into derivative contracts for a significant portion of our expected sales volumes.
- Pursue Ongoing Corporate Growth. The Company engages in prudent evaluation of potential acquisitions where we can take advantage of our core operational and engineering competencies.

Our Competitive Strengths

We believe the following combination of strengths will enable us to implement our strategies:

- High Quality Asset Base with Oil and Liquids Weighted Growth. As of December 31, 2014, we have accumulated approximately 70,000 net acres in the Wattenberg Field prospective for the Niobrara formation, of which, approximately 29,000 net acres are estimated to be prospective for the Codell formation. Our acreage is in an area noted for its high net oil and liquids content, with oil and NGLs comprising approximately 65% of proved reserves and approximately 70% of current sales volumes. We and other operators have consistently reported positive results in this area and believe our acreage position contains a large potential inventory of high value, ready to drill potential locations. Gathering systems and takeaway capacity in place in this area are continuously improving, enabling reduced time periods from well completion to first product sales.
- Contiguous Nature of Our Leasehold. Our acreage positions in the Wattenberg Field and in the Mid Continent region are highly contiguous allowing for more efficient field operations. In the Wattenberg Field, we believe our leasehold is particularly advantaged for development with horizontal wells and extended reach laterals.

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- High Degree of Operational Control. We operate approximately 98% of our proved reserves with an average working interest of approximately 86% providing us with significant control over the rate of development of our asset base. This allows us to employ the drilling and completion techniques we believe to be most effective, manage costs and control the timing and allocation of our capital expenditures.
- Gas Processing Capability in southern Arkansas. We own three gas processing facilities and 150 miles of gathering pipeline that principally serve our production from the Dorcheat Macedonia Field and our McKamie Patton Field properties. We believe the ownership of this gathering and processing infrastructure allows us to better control the timing of the development of our reserves, allows for high-grade drilling and improves our economics in southern Arkansas.
- Experienced Management Team with Proven Track Record. Our senior management team has extensive experience in the oil and gas industry. We believe our management and technical team is one of our principal competitive strengths due to their proven track record in execution and development of resource conversion opportunities. In addition, this team possesses substantial expertise in horizontal drilling techniques and fracture stimulation.
- Completion Techniques. We have tested various completion techniques, including increasing the number of fracture stimulation stages from 18 to 28, resulting in shorter fracture densities, and higher concentration of proppant near the wellbore. We have also significantly increased our application of longer laterals. We have seen encouraging results from these enhanced completion techniques and well design changes, and will continue to optimize those techniques to deliver improved results.
- Financial Flexibility. Our capital structure is intended to provide a high degree of financial flexibility to grow our asset base, both through organic projects and opportunistic acquisitions. Our liquidity as of December 31, 2014 was approximately $545.6 million, which was comprised of $543 million of availability under our senior secured revolving credit facility (“revolving credit facility”), if we elect to take advantage of our entire borrowing base (without giving effect to any scheduled or interim redetermination), and approximately $2.6 million of cash on hand. On February 6, 2015, the Company completed a public offering of 8,050,000 shares of common stock which generated net proceeds of approximately $202.6 million, after deducting underwriter discounts, commissions and estimated offering costs of $6.7 million. We have $14.0 million budgeted for leasehold, which limits non-discretionary spending. We currently do not have any long-term rig, fracture stimulation or sand commitments that would decrease the flexibility of our capital spending program. We also employ a disciplined approach to manage leverage and govern our organic capital spending programs. Please refer to Note 7-Long-Term Debt in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion on our revolving credit facility.

Our Operations

Our operations are mainly focused in the Wattenberg Field in the Rocky Mountain region and in the Dorcheat Macedonia Field in the Mid Continent region.

Rocky Mountain Region

The two main areas in which we operate in the Rocky Mountain region are the Wattenberg Field in Weld County, Colorado and the North Park Basin in Jackson County, Colorado. As of December 31, 2014, our estimated proved reserves in the Rocky Mountain region were 68,148 MBoe, which represented 76% of our total estimated proved reserves and contributed 17,531 Boe/d of sales volumes during 2014.

Wattenberg Field—Weld County, Colorado. Our operations are in the oil and liquids weighted extension area of the Wattenberg Field targeting the Niobrara and Codell formations. As of December 31, 2014, our Wattenberg position consisted of approximately 97,000 gross (70,000 net) acres. During 2014, we had a net increase of approximately 34,500 net acres in the Wattenberg Field. We own 3 D seismic surveys covering the majority of our acreage in the Wattenberg Field, which helps provide efficient and targeted horizontal drilling operations.

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The Wattenberg Field is now primarily developed for the Niobrara and Codell formations using horizontal drilling and multi stage fracture stimulation techniques. We believe the Niobrara B and C benches have been fully delineated on our legacy acreage, while the Codell formation continues to be delineated in our eastern legacy acreage. Our newly acquired acreage located north and south of the legacy acreage contains economic producing wells but will require additional drilling for full delineation. We expect these horizons to be the primary source of future production growth.

Our estimated proved reserves at December 31, 2014 in the Wattenberg Field were 67,849 MBoe. As of December 31, 2014, we had a total of 433 gross producing wells, of which 295 gross were horizontal wells, and our sales volumes during 2014 were 17,531 Boe/d, 95% of which came from horizontal wells. Our sales volumes for the fourth quarter of 2014 were 20,038 Boe/d. Our working interest for all producing wells averages approximately 82% and our net revenue interest is approximately 67%.

We continue to expand our proved reserves in this area by drilling non proved horizontal locations. As of December 31, 2014, we have an identified drilling inventory of approximately 226 gross (189 net) proved undeveloped ("PUD") drilling locations on our acreage with average well costs of $4.2 million. During 2014, we drilled 114 horizontal wells and completed 109.

During 2014, in the Niobrara B bench, we drilled 53 and completed 54 standard length (approximately 4,000 foot lateral) horizontal wells, three extended reach horizontal wells with an average lateral length of 9,280 feet, and four medium reach horizontal wells with an average lateral length of 6,514 feet that we plan to complete in 2015. Since we began our horizontal Niobrara B bench drilling program in 2011, through December 31, 2014, we have drilled and completed 156 wells of which 133 are on 80 acre spacing (six are extended reach lateral horizontal wells), three are on 60-acre spacing and 20 are on 40 acre spacing. We believe the results demonstrated by our wells spaced at 60 and 40 acres warrant continued development of the Niobrara B bench at 60 and 40-acre spacing. In addition, we believe the shallower decline curves demonstrated by our extended reach laterals warrant continued testing of lateral lengths greater than 4,000 feet.

During 2014, in the Niobrara C bench, we drilled 33 and completed 35 standard length (approximately 4,000 foot lateral) horizontal wells, one extended reach horizontal well with a lateral length of 9,114 feet and two medium reach horizontal wells with an average lateral length of 6,600 feet that we plan to complete in 2015. Since we began our horizontal Niobrara C bench drilling program in 2012, through December 31, 2014, we have drilled and completed 41 wells of which 35 are on 80 acre spacing (one an extended reach lateral horizontal well), two are on 60-acre spacing and four are on 40 acre spacing. We believe the results demonstrated by our wells spaced at 60 and 40 acres warrant continued development of the Niobrara C bench at 60 and 40-acre spacing. In addition, we believe the results of slower decline curves demonstrated by our extended reach lateral well warrants continued testing of lateral lengths greater than 4,000 feet. Late in the year, the Company drilled and completed one standard length horizontal well in the Niobrara A bench.

During 2014, in the Codell formation, we drilled 16 and completed 14 standard length (approximately 4,000 foot lateral) horizontal wells and one medium reach horizontal well with a lateral length of 6,931 feet. Since we began our horizontal Codell drilling program in 2012, through December 31, 2014, we have drilled and completed 19 wells on 160-acre spacing of which one is a medium reach lateral horizontal well. We believe the results of the medium reach lateral well warrants continued testing of lateral lengths of greater than 4,000 feet.

We estimate our capital expenditures in the Wattenberg Field for 2015 will be $380 million, which includes drilling and completing 37 horizontal wells in the Niobrara B bench, 33 horizontal wells in the Niobrara C bench and 7 horizontal wells in the Codell sandstone. The Company expects well costs to contract in the near term, targeting an average of approximately $4.0 million for a 4,000 foot lateral, down from $4.5 million in 2014, and $6.75 million for a 9,000 foot lateral, down from $7.5 million in 2014. The drilling program calls for the application of extended reach laterals for approximately 29% of the total program. The Company has allocated approximately $40 million to non-well capital, including $14 million to maintain leases and the remainder on essential infrastructure projects.

North Park Basin—Jackson County, Colorado. We control approximately 22,000 gross (17,000 net) acres in the North Park Basin in Jackson County, Colorado, all prospective for the Niobrara oil shale. We operate the North and South McCallum Fields, which currently produce light oil and carbon dioxide (“$CO_2$”) from the Dakota/Lakota Group sandstones and oil from a shallow waterflood in the Pierre B sandstone. Oil production is trucked to market, while $CO_2$ production is gathered to a nearby plant for processing.

In the North Park Basin, our estimated proved reserves as of December 31, 2014 were approximately 299 MBoe, 100% of which were crude oil. None of our $CO_2$ production is currently reflected in our reserve reports. During 2014, we drilled and successfully cored one vertical well which is currently being analyzed to determine a development plan for the basin.

Currently, there is no takeaway capacity for natural gas from the North Park Basin. Any future commercial development of the Niobrara shale in this area will require significant investment to construct the infrastructure necessary to gather and transport the produced associated natural gas. None of our 2015 capital budget is assigned to the North Park Basin.

Mid Continent Region

In southern Arkansas, we target the oil rich Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton Fields. As of December 31, 2014, our estimated proved reserves in the Mid-Continent region were 21,389 MBoe, 65% of which were oil and natural gas liquids and 69% of which were proved developed. We currently operate 277 producing vertical wells and, as of December 31, 2014, have an identified drilling inventory of approximately 86 gross (71.5 net) PUD drilling locations on our acreage with an average well cost of $1.8 million. During 2014, we drilled 48 wells and successfully completed 50 operated wells in the Mid-Continent region. We achieved a sales volume rate for 2014 of 5,978 Boe/d, of which 69% was from oil and NGLs, and a sales volume rate for the fourth quarter of 2014 of 6,538 Boe/d. Productive reservoirs range in depth from 4,500 to 9,000 feet. Those reservoirs include the Smackover and the Pettet, but our primary development target is the Cotton Valley. We budgeted capital expenditures for 2015 of approximately $40 million to drill 26 gross operated wells and perform approximately 70 recompletions.

Dorcheat Macedonia. In the Dorcheat Macedonia Field, we average an approximate 83% working interest and an approximate 68% net revenue interest on all producing wells, and the majority of our acreage is held by unitization, production, or drilling operations. We have approximately 243 gross producing wells and our production during 2014 was approximately 5,136 Boe/d (5,726 Boe/d sales volumes). During the fourth quarter of 2014, our production was 5,694 Boe/d (6,284 Boe/d sales volumes). Our proved reserves in this field are approximately 19,880 MBoe. During 2014, we continued to see positive test results from our 5-acre spacing project.

As of December 31, 2014, we have identified approximately 84 gross (70 net) PUD drilling locations on our acreage in this area. During 2014, we drilled 48 and successfully completed 50 vertical Cotton Valley wells in the Dorcheat Macedonia Field. In 2015, we expect to drill 21 PUD locations on 10 acre spacing with a complete cost per well of approximately $1.8 million. In addition, we expect to drill three wells on 5 acre spacing and perform approximately 70 recompletions on existing wells.

Other Mid Continent. We own additional interests in the McKamie Patton Field in the Mid Continent region near the Dorcheat Macedonia Field. As of December 31, 2014, our estimated proved reserves were approximately 1,509 MBoe, and sales volume during 2014 was approximately 252 Boe/d.

Gas Processing Facilities. Our Mid Continent gas processing facilities are located in Lafayette and Columbia counties in Arkansas and are strategically located to serve our production in the region. In the aggregate, our Arkansas gas processing facilities have approximately 40 MMcf/d of capacity with 86,000 gallons per day of associated natural gas liquids capacity. Our ownership of these facilities and related gathering pipeline provides us with the benefit of controlling processing and compression of our natural gas production and timing of connection to our newly completed wells.

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Reserves

Estimated Proved Reserves

The summary data with respect to our estimated proved reserves presented below has been prepared in accordance with rules and regulations of the Securities and Exchange Commission (the “SEC”) applicable to companies involved in oil and natural gas producing activities. Our reserve estimates do not include probable or possible reserves, categories which SEC rules do permit us to disclose in public reports. Our estimated proved reserves for the years ended December 31, 2014, 2013 and 2012 were determined using the preceding twelve months’ unweighted arithmetic average of the first day of the month prices. For a definition of proved reserves under the SEC rules, please see the Glossary of Oil and Natural Gas Terms included in the beginning of this report.

Reserve estimates are inherently imprecise and estimates for new discoveries are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The PV 10 values shown in the following table are not intended to represent the current market value of our estimated proved reserves. Neither prices nor costs have been escalated. The actual quantities and present values of our estimated proved reserves may be less than we have estimated.

The table below summarizes our estimated proved reserves at December 31, 2014, 2013 and 2012 for each of the regions and currently producing fields in which we operate. The proved reserve estimates at December 31, 2014 are based on reports prepared by our internal corporate reservoir engineering group, of which 100% were audited by Netherland, Sewell & Associates, Inc. (“NSAI”), our third party independent reserve engineers. The proved reserve estimates at December 31, 2013 and 2012 are based on reports prepared by NSAI and Cawley, Gillespie & Associates, Inc., respectively. In preparing these reports, NSAI and Cawley, Gillespie & Associates, Inc. evaluated 100% of our estimated proved reserves. For more information regarding our independent reserve engineers, please see Independent Reserve Engineers below. The information in the following table does not give any effect to or reflect our commodity derivatives.

| | At December 31, | | |
|---|---|---|---|
| Region/Field | 2014 | 2013 | 2012 |
| | (MMBoe) | | |
| Rocky Mountain | 68.1 | 49.1 | 32.4 |
| Wattenberg | 67.8 | 48.8 | 31.9 |
| North Park | 0.3 | 0.3 | 0.5 |
| Mid-Continent | 21.4 | 20.7 | 20.6 |
| Dorcheat Macedonia | 19.9 | 19.4 | 19.0 |
| McKamie Patton | 1.5 | 1.3 | 1.6 |
| Total | 89.5 | 69.8 | 53.0 |

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The following table sets forth more information regarding our estimated proved reserves at December 31, 2014, 2013 and 2012:

| | At December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Reserve Data(1): | | | |
| Estimated proved reserves: | | | |
| Oil (MMBbls) | 54.7 | 43.6 | 30.2 |
| Natural gas (Bcf) | 188.6 | 139.6 | 118.5 |
| Natural gas liquids (MMBbls) | 3.4 | 2.9 | 3.1 |
| Total estimated proved reserves (MMBoe)(2) | 89.5 | 69.8 | 53.0 |
| Percent oil and liquids | 65 % | 67 % | 63 % |
| Estimated proved developed reserves: | | | |
| Oil (MMBbls) | 28.3 | 20.7 | 14.3 |
| Natural gas (Bcf) | 94.5 | 59.2 | 48.9 |
| Natural gas liquids (MMBbls) | 2.2 | 1.6 | 1.3 |
| Total estimated proved developed reserves (MMBoe)(2) | 46.3 | 32.2 | 23.8 |
| Percent oil and liquids | 66 % | 69 % | 66 % |
| Estimated proved undeveloped reserves: | | | |
| Oil (MMBbls) | 26.4 | 22.9 | 15.8 |
| Natural gas (Bcf) | 94.1 | 80.4 | 69.6 |
| Natural gas liquids (MMBbls) | 1.2 | 1.3 | 1.8 |
| Total estimated proved undeveloped reserves (MMBoe)(2) | 43.2 | 37.6 | 29.2 |
| Percent oil and liquids | 64 % | 64 % | 60 % |

(1) Proved reserves were calculated using prices equal to the twelve month unweighted arithmetic average of the first day of the month prices for each of the preceding twelve months, which were $94.99 per Bbl WTI and $4.35 per MMBtu HH, $96.91 per Bbl WTI and $3.67 per MMBtu HH, and $94.71 per Bbl WTI and $2.76 per MMBtu HH for the years ended December 31, 2014, 2013 and 2012, respectively. Adjustments were made for location and grade.

(2) Determined using the ratio of 6 Mcf of natural gas being equivalent to one Bbl of crude oil.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic productivity at greater distances. All proved undeveloped locations in our December 31, 2014 reserves report are included in our development plan and are scheduled to be drilled within five years from their initial proved booking date. The Company’s financial group evaluated the proved undeveloped drilling plan using the Company’s current budget price deck and determined that the internally generated cashflows over the next five years would sufficiently fund the proved undeveloped development program. The reliable technologies used to establish our proved reserves are a combination of pressure performance, geologic mapping, offset productivity, electric logs, and production data.

Estimated proved reserves at December 31, 2014 were 89.5 MMBoe, a 28% increase from estimated proved reserves of 69.8 MMBoe at December 31, 2013. The net increase in reserves of 19.7 MMBoe is the result of additions in extensions and discoveries of 20.2 MMBoe, primarily due to the development of the Niobrara B and C benches and the Codell formations in the Wattenberg Field, coupled with a net positive revision of 7.1 MMBoe (engineering and pricing) and net acquisitions (acquisitions less divestitures) of 0.8 MMBoe offset by 8.4 MMBoe in production. The addition in extension and discoveries is primarily the result of drilling and completing 99 unproved horizontal locations (including 12 non-operated) in the Niobrara and the Codell formations in the Wattenberg Field during 2014 and the addition of 37 new horizontal proved undeveloped locations directly offsetting new wells brought online in 2014. As of December 31, 2014, approximately 70% of our horizontal development in the Wattenberg Field was in the Niobrara B formation, the

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majority of which was on 80-acre spacing. The net positive engineering revision is primarily the result of adding new Niobrara B proved undeveloped locations on 80-acre spacing, directly offsetting economic proved producing Niobrara B wells drilled prior to 2014, diagonal offsets to economic Niobrara B proved producing wells and a relatively small number of locations greater than one offset to economic Niobrara B proved producing wells but within developed areas and surrounded by Niobrara B proved producing wells. A total of 119 horizontal proved undeveloped locations were added to the proved reserves at December 31, 2014 of which 86 (72%) were direct offsets to economic proved producing wells (drilled in 2014 or prior to 2014), 21 (18%) were direct offsets in a diagonal pattern to economic proved producing wells and 12 (10%) were greater than one offset from economic proved producing wells. The reasonable certainty of the reserves associated with the latter two categories of proved undeveloped locations is based on analysis of the immediate surrounding productivity of the Niobrara B bench and detailed geologic mapping. All Niobrara proved undeveloped locations are spaced on 80 acres although testing is ongoing on 60-acre and 40-acre spacing. The positive engineering revision was offset by a small negative performance revision of approximately 540 MBoe. A negative pricing revision of 0.25 MMBoe resulted from a decrease in average commodity price from $96.91 per Bbl WTI and $3.67 per MMBTU HH for the year ended December 31, 2013 to $94.99 per Bbl WTI and $4.35 per MMBTU HH for the year ended December 31, 2014.

Estimated proved reserves at December 31, 2013 were 69.8 MMBoe, a 32% increase from estimated proved reserves of 53.0 MMBoe at December 31, 2012. The net increase in reserves of 16.8 MMBoe resulting from development in the Wattenberg Field was comprised of 28.9 MMBoe of additions in extensions and discoveries offset by 3.8 MMBoe in sales volumes and negative revisions of 8.3 MMBoe. The negative revision results primarily from a combination of eliminating 45 net vertical locations from proved undeveloped due to the change in focus from vertical to horizontal development, the elimination of all proved non producing reserves associated with vertical well refracs, recompletions, and lower performance from our vertical producers due to increased line pressure. The addition in extension and discoveries is the result of drilling and completing 68 unproved horizontal locations (including 4 non operated) in the Wattenberg Field during 2013 and the addition of 89 new horizontal proved undeveloped locations. A net increase in reserves of 0.1 MMBoe in the Mid Continent region resulted from the drilling and completion of our 5 acre increased density pilots in the Cotton Valley formation offset by a negative revision resulting from lower than expected proved developed performance. A small positive pricing revision of 0.51 MMBoe resulted from an increase in average commodity price from $94.71 per Bbl WTI and $2.76 per MMBtu HH for the year ended December 31, 2012 to $96.91 per Bbl WTI and $3.67 per MMBtu HH for the year ended December 31, 2013.

Estimated proved reserves at December 31, 2012 were 53.0 MMBoe, a 21% increase from estimated proved reserves of 43.7 MMBoe at December 31, 2011. The net increase in reserves of 9.3 MMBoe resulted from development in the Wattenberg Field was comprised of 18.9 MMBoe of additions in extensions and discoveries offset by 3.5 MMBoe in sales volumes and negative revisions of 6.1 MMBoe. The negative revision resulted from a combination of eliminating 50 locations from proved undeveloped due to the change in focus from vertical to horizontal development and lower performance from our vertical producers. The addition in extension and discoveries was the result of drilling and completing 65 unproved locations in the Wattenberg Field during 2012 (approximately 50% horizontal Niobrara B bench locations, 50% vertical development) and the addition of 63 new proved undeveloped locations (100% horizontal Niobrara B bench locations). A net increase in reserves of 0.68 MMBoe in the Mid Continent region resulted from continued development of the Cotton Valley formation. Proved reserves decreased by 0.67 MMBoe with the divestiture of the majority of our California properties. A small negative pricing revision of 0.1 MMBoe resulted from a decrease in commodity price from $96.19 per Bbl WTI and an average price of $4.12 per MMBtu HH for the year ended December 31, 2011 to $94.71 per Bbl WTI and $2.76 per MMBtu HH for the year ended December 31, 2012.

Reconciliation of PV 10 to Standardized Measure

PV 10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV 10 is a computation of the Standardized Measure on a pre tax basis. PV 10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV 10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We

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use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV 10, however, is not a substitute for the Standardized Measure. Our PV 10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV 10 to Standardized Measure at December 31, 2014, 2013 and 2012:

| | December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in millions) | | |
| PV-10 | $ 1,340.5 | $ 1,227.2 | $ 834.7 |
| Present value of future income taxes discounted at 10% | (233.1) | (301.9) | (151.3) |
| Standardized Measure | $ 1,107.4 | $ 925.3 | $ 683.4 |

Proved Undeveloped Reserves

| | Net Reserves, MBoe | | |
|---|---|---|---|
| | At December 31, | | |
| | 2014 | 2013 | 2012 |
| Beginning of year | 37,603 | 29,192 | 26,652 |
| Converted to proved developed | (7,791) | (3,047) | (5,166) |
| Additions from capital program | 5,596 | 16,535 | 13,913 |
| Acquisitions (sales) | — | 1,779 | (430) |
| Revisions | 7,838 | (6,856) | (5,777) |
| End of year | 43,246 | 37,603 | 29,192 |

At December 31, 2014, our proved undeveloped reserves were 43,246 MBoe, all of which are scheduled to be drilled within five years of their initial proved date. During 2014, the Company converted 21% of its proved undeveloped reserves (58 wells, 7,791 MBoe) at a cost of $116.9 million. Executing our 2014 capital program resulted in the addition of 5,596 MBoe (45 wells) in proved undeveloped reserves. The positive engineering revision of 7,838 MBoe was primarily the result of adding 49 new proved undeveloped locations in Wattenberg on 80-acre spacing, directly offsetting economic proved producing wells drilled prior to 2014, 21 diagonal offsets to economic proved producing wells and 12 proved undeveloped locations positioned greater than one offset to economic proved producing wells but within developed areas and surrounded by proved producing wells. Also included in the revision category was the removal from proved undeveloped locations of 15 horizontal locations in the Wattenberg Field that were no longer spaced on 80 acres following the 2014 capital drilling program and all of the vertical proved undeveloped locations in the Wattenberg Field which have been replaced by horizontal wells or are expected to be replaced in the future. Proved undeveloped locations remaining in the category from December 31, 2013 received a downward revision of 214 Mboe.

At December 31, 2013, our proved undeveloped reserves were 37,603 MBoe, all of which were scheduled to be drilled within five years of their initial disclosure. During 2013, 3,047 MBoe or 10% of our proved undeveloped reserves (40 wells) were converted into proved developed reserves requiring $62.8 million of drilling and completion capital. Continued delineation and testing in our Wattenberg Field in 2013 resulted in a conversion rate less than 20% for the year. Execution of our 2013 capital program resulted in the addition of 16,535 MBoe in proved undeveloped reserves (92 wells). The negative revision of 6,856 MBoe resulted from a combination of eliminating vertical proved undeveloped locations in the Wattenberg Field continuing the transition to horizontal development and a reduction in proved undeveloped reserves in the Dorcheat Macedonia Field based on proved developed performance.

At December 31, 2012, our proved undeveloped reserves were 29,192 MBoe, all of which were scheduled to be drilled within five years of their initial disclosure. During 2012, 5,166 MBoe or 19.4% of our proved undeveloped reserves (89 wells) were converted into proved developed reserves requiring $128.9 million of drilling and completion capital and $16.2 million of capital primarily used to expand our Dorcheat Macedonia gas plant. Executing our 2012 capital program resulted in the addition of 13,913 MBoe in proved undeveloped reserves (83 wells). Sales of the majority of our California properties during 2012 reduced our proved undeveloped reserves by 430 MBoe. The negative revision of 5,777 MBoe results from a combination of eliminating 50 locations in the Wattenberg Field from proved undeveloped due to the change in focus from vertical to horizontal development and the reduction in remaining vertical proved undeveloped reserves as a result of lower performance from our vertical producers.

Internal controls over reserves estimation process

Our policies regarding internal controls over the recording of reserves estimates require reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The Company's Reserve Committee reviews significant reserve changes on an annual basis and our third party independent reserve engineers, NSAI, is engaged by and has direct access to the Reserve Committee. NSAI audited 100% of our estimated proved reserves at December 31, 2014 and evaluated 100% of our estimated proved reserves in the preparation of our reserve report at December 31, 2013. Cawley, Gillespie & Associates, Inc. evaluated 100% of our estimated proved reserves in the preparation of our reserve report at December 31, 2012.

Responsibility for compliance in reserves estimation is delegated to our internal corporate reservoir engineering group managed by Lynn E. Boone. Ms. Boone is our Senior Vice President, Planning & Reserves. Ms. Boone attended the Colorado School of Mines and graduated in 1982 with a Bachelor of Science degree in Chemical and Petroleum Refining Engineering. She attended the University of Oklahoma and graduated in 1985 with a Master of Science degree in Petroleum Engineering. Ms. Boone has been involved in evaluations and the estimation of reserves and resources for over 31 years. She has managed the technical reserve process at a company level for over ten years. Collectively with Ms. Boone, out internal corporate reservoir engineering group has over 100 years of experience.

Our technical team works with our banking syndicate members at least twice each year for a valuation of our reserves by the banks in our lending group and their engineers in determining the borrowing base under our revolving credit facility.

Independent Reserve Engineers

The reserves estimates for the years ended December 31, 2014 and 2013 shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates set forth in the NSAI audit letter incorporated herein are Mr. Dan Smith and Mr. John Hattner. Mr. Smith, a Licensed Professional Engineer in the State of Texas (No. 49093), has been practicing consulting petroleum engineering at NSAI since 1980 and has over 7 years of prior industry experience. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 559), has been practicing consulting petroleum geoscience at NSAI since 1991, and has over 11 years of prior industry experience. He graduated from University of Miami, Florida, in 1976 with a Bachelor of Science Degree in Geology; from Florida State University in 1980 with a Master of Science Degree in Geological Oceanography; and from Saint Mary's College of California in 1989 with a Master of Business Administration Degree. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The proved reserves estimate for the Company for the year ended December 31, 2012 shown herein have been independently prepared by Cawley, Gillespie & Associates, Inc., which was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F 693. Within Cawley, Gillespie & Associates, Inc., the technical person primarily responsible for preparing the estimates shown herein was Zane Meekins. Mr. Meekins has been a petroleum engineering consultant at Cawley, Gillespie & Associates, Inc. since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 26 years of practical experience in petroleum engineering, with over 24 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University with a BS in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

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Production, Revenues and Price History

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. The decline in natural gas prices is being driven primarily by warmer than anticipated weather with an abundant inventory of natural gas. Oil prices drastically declined in the fourth quarter of 2014 due in part to a stronger U.S. dollar and emerging global supply and demand imbalances caused by weaker than expected demand growth and significant supply growth in North America.

Demand is impacted by general economic conditions, public perception, weather and other seasonal conditions, including hurricanes and tropical storms. Supply is impacted by the price per barrel of oil and natural gas, service costs, global politics, and demand. Over or under supply of oil or natural gas can result in substantial price volatility. Recently, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets. We currently believe that we have the means necessary to fully fund our 2015 capital program in the current pricing environment.

The following table sets forth information regarding oil and natural gas production, sales prices, and production costs for the periods indicated. For additional information on price calculations, please see information set forth in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 (1) | 2013 (1) | 2012 (1) |
| Oil: | | | |
| Total Production (MBbls) | 5,618.7 | 3,887.2 | 2,191.0 |
| Wattenberg Field | 4,486.4 | 2,775.6 | 1,190.8 |
| Dorcheat Macedonia Field | 1,025.6 | 925.2 | 789.5 |
| Average sales price (per Bbl), including derivatives(2) | $ 84.00 | $ 88.82 | $ 88.40 |
| Average sales price (per Bbl), excluding derivatives(2) | $ 81.95 | $ 91.84 | $ 89.08 |
| Natural Gas: | | | |
| Total Production (MMcf) | 15,316.1 | 9,975.9 | 5,473.2 |
| Wattenberg Field | 11,372.7 | 6,269.1 | 2,485.6 |
| Dorcheat Macedonia Field | 4,030.6 | 3,598.3 | 2,973.8 |
| Average sales price (per Mcf), including derivatives(2) | $ 5.16 | $ 4.70 | $ 3.76 |
| Average sales price (per Mcf), excluding derivatives(2) | $ 5.11 | $ 4.66 | $ 3.62 |
| Natural Gas Liquids: | | | |
| Total Production (MBbls) | 260.6 | 352.8 | 284.7 |
| Wattenberg Field | 16.8 | 10.2 | — |
| Dorcheat Macedonia Field | 243.8 | 342.6 | 284.7 |
| Average sales price (per Bbl), including derivatives | $ 49.14 | $ 51.74 | $ 55.54 |
| Average sales price (per Bbl), excluding derivatives | $ 49.14 | $ 51.74 | $ 55.54 |
| Oil Equivalents: | | | |
| Total Production (MBoe) | 8,365.6 | 5,902.7 | 3,387.9 |
| Wattenberg Field | 6,398.6 | 3,830.7 | 1,605.0 |
| Dorcheat Macedonia Field | 1,874.7 | 1,867.5 | 1,569.8 |
| Average Daily Production (Boe/d) | 22,919.3 | 16,171.8 | 9,257.0 |
| Wattenberg Field | 17,530.5 | 10,495.0 | 4,385.4 |
| Dorcheat Macedonia Field | 5,136.3 | 5,116.4 | 4,289.1 |

| | | | |
|---|---|---|---|
| Average Production Costs (per Boe) | $ 8.44 | $ 8.09 | $ 9.06 |

(1) Amounts reflect results for continuing operations and exclude results for discontinued operations related to non core properties in California sold or held for sale as of December 31, 2014, 2013 and 2012.
(2) Excludes ad valorem and severance taxes.

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Principal Customers

Three of our customers, Plains Marketing LP, Lion Oil Trading & Transportation, Inc. and High Sierra Crude Oil & Marketing comprised 29%, 19% and 11%, respectively, of our total revenue for the year ended December 31, 2014. No other single non affiliated customer accounted for 10% or more of oil and natural gas sales in 2014. We believe the loss of any one customer would not have a material effect on our financial position or results of operations because there are numerous potential customers of our production.

Delivery Commitments

We have entered into two purchase and transportation agreements to deliver a fixed determinable quantity of crude oil. The first agreement is anticipated to take effect during the second quarter of 2015 for 12,580 barrels per day over an initial five year term. The second agreement is anticipated to take effect during the third quarter of 2016 for 15,000 barrels per day over an initial seven year term. The aggregate financial commitment fee is approximately $540 million over the initial terms of the agreements. While the volume commitment may be met with Company volumes or third party volumes, the Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments.

Productive Wells

The following table sets forth the number of producing oil and natural gas wells in which we owned a working interest at December 31, 2014.

| | Oil | | Natural Gas(1) | | Total | | Operated | |
|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Rocky Mountain | 485 | 408.3 | — | — | 485 | 408.3 | 419 | 396.0 |
| Mid-Continent | 277 | 233.7 | — | — | 277 | 233.7 | 269 | 233.4 |
| Total | 762 | 642 | — | — | 762 | 642.0 | 688 | 629.4 |

(1) All gas production is associated gas from producing oil wells.

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Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2014 for each of the areas where we operate along with the PV 10 values of each. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

| | Developed Acres | | Undeveloped Acres | | Total Acres | | |
|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | PV-10 |
| Rocky Mountain | 62,831 | 53,247 | 55,945 | 33,703 | 118,776 | 86,950 | $ 986,676 |
| Wattenberg Field | 54,972 | 45,388 | 41,877 | 24,748 | 96,849 | 70,136 | 981,414 |
| Other Rocky Mountain | 7,859 | 7,859 | 14,068 | 8,955 | 21,927 | 16,814 | 5,262 |
| Mid-Continent | 6,317 | 4,784 | 6,250 | 4,437 | 12,567 | 9,221 | 353,786 |
| Dorcheat Macedonia Field | 4,507 | 3,114 | 2,320 | 1,308 | 6,827 | 4,422 | 317,620 |
| Other Mid-Continent | 1,810 | 1,670 | 3,930 | 3,129 | 5,740 | 4,799 | 36,166 |
| Total | 69,148 | 58,031 | 62,195 | 38,140 | 131,343 | 96,171 | $ 1,340,462 |

Undeveloped acreage

The following table sets forth the number of net undeveloped acres as of December 31, 2014 that will expire over the next three years by area unless production is established within the spacing units covering the acreage prior to the expiration dates:

| | Expiring 2015 | | Expiring 2016 | | Expiring 2017 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Rocky Mountain (1) | 19,847 | 13,359 | 10,316 | 4,525 | 1,490 | 856 |
| Mid-Continent | 57 | 43 | 883 | 581 | 82 | 20 |
| Total | 19,904 | 13,402 | 11,199 | 5,106 | 1,572 | 876 |

(1) Our 2015 budget allocates $14 million to maintain the vast majority of our acreage within the Rocky Mountain region that is currently set to expire in 2015.

Drilling Activity

The following table describes the exploratory and development wells we drilled and completed during the years ended December 31, 2014, 2013 and 2012.

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Exploratory | | | | | | |
| Productive Wells | — | — | — | — | — | — |
| Dry Wells | — | — | 1 | 1 | 1 | 1 |
| Total Exploratory | — | — | 1 | 1 | 1 | 1.0 |
| Development | | | | | | |
| Productive Wells | 142 | 124.3 | 117 | 102.7 | 149 | 140.9 |
| Dry Wells | — | — | — | — | — | — |
| Total Development | 142 | 124.3 | 117 | 102.7 | 149 | 140.9 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total | 142 | 124.3 | 118 | 103.7 | 150 | 141.9 |

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The following table describes the present operated drilling activities as of December 31, 2014.

| | As of December 31, 2014 | |
|---|---|---|
| | Gross | Net |
| Exploratory | | |
| Rocky Mountain | — | — |
| Mid-Continent | — | — |
| Total Exploratory | — | — |
| Development | | |
| Rocky Mountain | 21 | 13.8 |
| Mid-Continent | — | — |
| Total Development | 21 | 13.8 |
| Total | 21 | 13.8 |

Capital Expenditure Budget

Our anticipated 2015 capital budget is $420 million a decrease of approximately 37% as compared to 2014. We plan to spend approximately $380 million or 90% of our total 2015 budget in the Rocky Mountain region to drill and complete approximately 77 wells and build infrastructure in the Wattenberg Field. We plan to spend approximately $40 million in the Rocky Mountain region on non-well capital, including approximately $14 million to maintain leases and the remainder on essential infrastructure projects. In the Mid Continent region, we plan to spend approximately $40 million during 2015 to drill 26 gross operated wells and perform approximately 70 recompletions. The ultimate amount of capital we will expend may fluctuate materially based on, among other things, market conditions, the success of our drilling results as the year progresses and changes in the borrowing base under our revolving credit facility.

Derivative Activity

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo political factors that we can neither control nor predict. We attempt to mitigate a portion of our price risk through the use of derivative contracts.

As of December 31, 2014, and through the filing date of this report, we had the following economic derivatives in place, which settle monthly:

| Settlement Period | Derivative Instrument | Total Volumes (Bbls/MMBtu per day) | Average Fixed Price | Average Short Floor Price (Short-Put) | Average Floor Price (Long-Put) | Average Ceiling Price | Fair Market Value of Asset (Liability) |
|---|---|---|---|---|---|---|---|
| Oil | | | | | | | (in thousands) |
| 1Q 2015 | Swap | 6,000 | $ 95.39 | | | | $ 22,363 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2Q 2015 | Swap | 5,000 | $ 94.41 | | | | 17,497 |
| 3Q 2015 | Swap | 2,000 | $ 93.43 | | | | 6,534 |
| 4Q 2015 | Swap | 2,000 | $ 93.43 | | | | 6,170 |
| 1Q 2015 | 3-Way Collar | 6,500 | | $ 68.08 | $ 84.32 | $ 95.90 | 9,264 |
| 2Q 2015 | 3-Way Collar | 5,500 | | $ 67.73 | $ 84.09 | $ 95.16 | 7,275 |
| 3Q 2015 | 3-Way Collar | 6,500 | | $ 68.46 | $ 84.62 | $ 95.49 | 7,846 |
| 4Q 2015 | 3-Way Collar | 6,500 | | $ 68.46 | $ 84.62 | $ 95.49 | 7,091 |
| 2016 | 3-Way Collar | 5,500 | | $ 70.00 | $ 85.00 | $ 96.83 | 17,765 |
| | | | | | | | $ 101,805 |
| Gas | | | | | | | |
| 1Q 2015 | 3-Way Collar | 15,000 | | $ 3.50 | $ 4.00 | $ 4.75 | $ 2,200 |
| | | | | | | | $ 2,200 |
| Total | | | | | | | $ 104,005 |

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The Company has hedged a significant portion of anticipated oil production in 2015 with fixed price contracts and three-way collars. Currently, forward oil prices are below the average price of our short-puts associated with our three-way collars. Should monthly crude oil settlement prices occur below the strike price of our short-puts associated with the Company's three-way collars, we will receive a payment from our hedging counterparty equal to the difference between the strike prices of the short-put and long-put multiplied by the monthly volume associated with the three-way collar.

We do not apply hedge accounting treatment to any commodity derivative contracts. Settlements on these contracts and adjustments to fair value are shown as a component of derivative gain (loss). See Note 13—Derivatives to our consolidated financial statements for additional information regarding our derivative instruments.

Title to Properties

Our properties are subject to customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes and other industry related constraints, including leasehold restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business. We believe that we generally have satisfactory title to or rights in all of our producing properties. Generally, we undergo thorough title review and receive title opinions from legal counsel before we commence drilling operations, subject to the availability and examination of accurate title records. Although in certain cases, title to our properties is subject to interpretation of multiple conveyances, deeds, reservations, and other constraints, we believe that none of these will materially detract from the value of our properties or from our interest therein or will materially interfere with the operation of our business.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, attracting and retaining qualified personnel, and obtaining transportation for the oil and gas we produce in certain regions. There is also competition between producers of oil and gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 65% of our estimated proved reserves as of December 31, 2014 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2014, the daily NYMEX WTI oil spot price ranged from a high of $107.62 per Bbl to a low of $53.27 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu. As of the date of filing, we had commodity price derivative agreements for 2015 on approximately 60% of our anticipated production based on the mid point of our guidance range of 27,800 Boe/d to 30,700 Boe/d.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, and regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC"), and the courts. We cannot predict when or whether any such proposals or proceedings may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen incidents may occur or past non compliance with laws or regulations may be discovered.

Regulation of transportation of oil

Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by FERC pursuant to the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products (collectively referred to as "petroleum pipelines") be just and reasonable and non discriminatory and that such rates and terms and conditions of service be filed with FERC.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act ("NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act ("NGA"), and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

FERC issued a series of orders in 1996 and 1997 to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although 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.

The Domenici Barton Energy Policy Act of 2005 ("EP Act of 2005"), is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation more accessible to natural gas services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti market manipulation rule does not apply to activities that relate only to intrastate or other non jurisdictional sales or gathering, but does apply to activities of 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" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although nondiscriminatory take regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act ("CEA"), and regulations promulgated thereunder by the Commodity Futures Trading Commission ("CFTC"). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. 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 that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that 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 or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

We own interests in properties located onshore in two U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas.

Regulation of derivatives and reporting of government payments

The Dodd Frank Wall Street Reform and Consumer Protection Act (the “Dodd Frank Act”) was passed by Congress and signed into law in July 2010. The Dodd Frank Act is designed to provide a comprehensive framework for the regulation of the over the counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd Frank Act subjects swap dealers and major swap participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end users. In addition, in August 2012, the SEC issued a final rule under Section 1504 of the Dodd Frank Act, Disclosure of Payment by Resource Extraction Issuers, which would have required resource extraction issuers, such as us, to file annual reports that provide information about the type and total amount of payments made for each project related to the commercial development of oil, natural gas, or minerals to each foreign government and the federal government. In July 2014, the U.S. District Court for the District of Columbia vacated the rule, and the SEC has announced it will not appeal the court’s decision. However, the SEC may propose revised resource extraction payments disclosure rules applicable to our business.

Environmental, Health and Safety Regulation

Our natural gas and oil exploration and production operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing safety and health, the discharge of materials into the environmental or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of permits before drilling or other regulated activity commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; establish specific safety and health criteria addressing worker protection and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

The following is a summary of the more significant existing environmental and health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and waste handling

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (“CERCLA”), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these potentially “responsible persons” may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances but we are not aware of any liabilities for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act (“RCRA”), and analogous state laws, impose requirements on the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes certain drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies under RCRA’s less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that are regulated as hazardous wastes. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes were not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including groundwater contaminated by prior owners or operators), to pay

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for damages for the loss or impairment of natural resources, and to take measures to prevent future contamination from our operations.

Pipeline safety and maintenance

Pipelines, gathering systems and terminal operations are subject to increasingly strict safety laws and regulations. Both the transportation and storage of refined products and crude oil involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages, and significant business interruption. The U.S. Department of Transportation has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of our pipeline and storage facilities. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. The Pipeline Safety, Regulatory Certainty, and Job Creation Act was signed into law in early 2012. In addition, the Pipeline and Hazardous Materials Safety Administration has issued new rules to strengthen federal pipeline safety enforcement programs.

Air emissions

The Clean Air Act ("CAA") and comparable state laws and regulations restrict the emission of air pollutants from many sources, including oil and gas operations, and impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining required air permits can significantly delay the development of certain oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues.

For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non wildcat and non delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2014. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA issued revised rules in 2013 and 2014 in response to some of these requests. Specifically, on September 23, 2013, the EPA published a final amendment extending the compliance dates for certain groups of storage vessels to April 15, 2014 and April 15, 2015, and on December 31, 2014, the EPA issued a final amendment clarifying certain reduced emission completion requirements.

On December 17, 2014, the United States Environmental Protection Agency (the ‘‘EPA’’) proposed to revise and lower the existing 75 ppb national ambient air quality standard (‘‘NAAQS’’) for ozone under the federal Clean Air Act to a range within 65-70 ppb. The EPA is also taking public comment on whether the ozone NAAQS should be revised as low as 60 ppb. A lowered ozone NAAQS in a range of 60-70 ppb could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. In addition, in February

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2014, the Colorado Department of Public Health and Environment's Air Quality Control Commission ("AQCC") adopted new and revised air quality regulations that impose stringent new requirements to control emissions from existing and new oil and gas facilities in Colorado. The proposed regulations include new control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in Colorado. For example, the new regulations impose Storage Tank Emission Management ("STEM") requirements for certain new and existing storage tanks. The STEM requirements require us to install costly emission control technologies as well as monitoring and recordkeeping programs at most of our new and existing well production facilities. The new Colorado regulations also impose a Leak Detection and Repair ("LDAR") program for well production facilities and compressor stations. The LDAR program primarily targets hydrocarbon (i.e., methane) emissions from the oil and gas sector in Colorado and represents a significant new use of state authority regarding these emissions.

Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. However, we do not currently believe that compliance with such requirements will have a material adverse effect on our operations.

Climate change

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit requirements for certain large stationary sources that include potential major sources of GHG emissions. Facilities required to obtain PSD permits for their non-GHG emissions may also be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHGs from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has, from time to time, considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Most recently, the EPA proposed rules to further reduce GHG emissions, primarily from coal-fired power plants, under its Clean Power Plan. If adopted, the Clean Power Plan could affect the demand for products we supply or otherwise affect our operations. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. President Obama has indicated that climate change and GHG regulation is a significant priority for his second term. The President issued a Climate Action Plan in June 2013, calling for, among other things, a reduction in methane emissions from the oil and gas industry. In January 2015, the EPA announced a comprehensive strategy intended to further reduce methane emissions from the oil and gas sector. Proposed methane rules are expected in 2015 with a final rule in 2016 and may include additional control, monitoring, recordkeeping or reporting requirements applicable to our operations. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on

GHG emissions could adversely affect demand for the oil and natural gas we produce.

Most recently, in June 2014, the United States Supreme Court ruled in Utility Air Regulatory Group v. EPA, No. 12 1146. The Supreme Court upheld part of EPA's GHG-related regulations but struck down other portions of the rules. Specifically, the Supreme Court ruled that sources subject to the PSD or Title V programs because of non-GHG emissions could still potentially be subject to certain "best available control technology" requirements applicable to their

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GHG emissions. Under the Court's opinion, sources subject to the PSD or Title V programs due solely to their GHG emissions, however, can no longer be subject to EPA's GHG permitting requirements.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Water discharges

The Federal Water Pollution Control Act or the Clean Water Act ("CWA") and analogous state laws impose restrictions and controls regarding the discharge of pollutants into certain surface waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or underlying state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). Obtaining permits has the potential to delay the development of natural gas and oil projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in certain quantities that may impose substantial potential liability for the costs of removal, remediation and damages. The EPA and Corps have issued a proposed rule that would define the scope of jurisdictional waters of the United States under the CWA. An expansive definition of such waters could affect our ability to operate in certain areas and may increase our costs of operations and permitting.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations, and further believe we are in substantial compliance with the terms thereof. As properties are acquired, we determine the need for new or updated SPCC plans and, where necessary, will develop or update such plans to implement physical and operation controls, the costs of which are not expected to be material.

Endangered Species Act

The federal Endangered Species Act restricts activities that may affect endangered and threatened species or their habitats. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (the "OSH Act"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSH Act's hazard communication standard, the EPA community right to know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations, and that this information be provided to employees, state and local government authorities and citizens.

Hydraulic fracturing

Regulations relating to hydraulic fracturing. We are subject to extensive federal, state, and local laws and regulations concerning health, safety, and environmental protection. Government authorities frequently add to those requirements, and both oil and gas development generally and hydraulic fracturing specifically are receiving increasing regulatory attention. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

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States have historically regulated oil and gas exploration and production activity, including hydraulic fracturing. State governments in the areas where we operate have adopted or are considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Such measures may address any risk to drinking water, the potential for hydrocarbon migration and disclosure of the chemicals used in fracturing. Colorado, for example, comprehensively updated its oil and gas regulations in 2008 and adopted significant additional amendments in 2011 and 2013. Among other things, the updated and amended regulations require operators to reduce methane emissions associated with hydraulic fracturing, compile and report additional information regarding well bore integrity, publicly disclose the chemical ingredients used in hydraulic fracturing, increase the minimum distance between occupied structures and oil and gas wells, undertake additional mitigation for nearby residents, and implement additional groundwater testing. In 2014, the State enacted legislation to increase the potential sanctions for statutory, regulatory and other violations. Among other things, this legislation and its implementing regulations mandate monetary penalties for certain types of violations, require a penalty to be assessed for each day of violation and significantly increase the maximum daily penalty amount. Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions of our operations.

The federal Safe Drinking Water Act (“SDWA”) and comparable state statutes may restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids, primarily via disposal wells or enhanced oil recovery (“EOR”) wells, is governed by federal or state regulatory authorities that, in some cases, include the state oil and gas regulatory or the state’s environmental authority. The federal Energy Policy Act of 2005 amended the Underground Injection Control, provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of “underground injection,” but disposal of hydraulic fracturing fluids and produced water or their injection for EOR is not excluded. The U.S. Senate and House of Representatives have considered bills to repeal this SDWA exemption for hydraulic fracturing. If enacted, hydraulic fracturing operations could be required to meet additional federal permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, meet plugging and abandonment requirements, and provide additional public disclosure of chemicals used in the fracturing process as a consequence of additional SDWA permitting requirements.

Federal agencies are also considering additional regulation of hydraulic fracturing. The EPA has published guidance for issuing underground injection permits that would regulate hydraulic fracturing using diesel fuel. This guidance eventually could encourage other regulatory authorities to adopt permitting and other restrictions on the use of hydraulic fracturing. In addition, on October 21, 2011, the EPA announced its intention to propose regulations under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. These proposed regulations are expected in early 2015. The EPA is also collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. The EPA issued a progress report regarding the study in December 2012, which described generally the continuing focus of the study, but did not provide any data, findings, or conclusions regarding the safety of hydraulic fracturing operations. A draft of the report is expected in 2015 and a final, peer reviewed report is expected in 2016. The results of this study could result in additional regulations, which could lead to operational burdens similar to those described above. The EPA also has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act (“TSCA”) to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to the TSCA rulemaking. On January 7, 2015, several national environmental advocacy groups filed a lawsuit requesting that the EPA add the oil and gas extraction industry to the list of industries required to report releases of certain “toxic chemicals” under EPA’s Toxics Release Inventory (TRI) program. The United States Department of the Interior has also proposed a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The Bureau of Land Management (BLM) has also indicated its intent to pursue a rulemaking related to further controlling the venting and flaring of natural gas on BLM land. And the U.S. Occupational Safety and Health Administration has proposed stricter standards for worker exposure to silica, which would apply to use of sand as a proppant for hydraulic fracturing.

Apart from these ongoing federal and state initiatives, local governments are adopting new requirements on hydraulic fracturing and other oil and gas operations. For example, voters in the cities of Fort Collins, Boulder and

Lafayette, Colorado recently approved bans of varying lengths on hydraulic fracturing within their respective city limits. The bans in Longmont, Lafayette, and Fort Collins were overturned by local district courts, the Boulder and Broomfield bans remain in place, and the Boulder County moratorium was recently extended to 2018. The Longmont City Council has appealed the district court's decision to overturn the ban, and Fort Collins is appealing that court decision as well. In addition, bans to restrict hydraulic fracturing have been proposed in the states of Pennsylvania and Ohio, and New York recently enacted a permanent moratorium on all hydraulic fracturing activities. Any successful bans or moratoriums where we operate could increase the costs of our operations, impact our profitability, and even prevent us from drilling in certain locations.

At this time, it is not possible to estimate the potential impact on our business of recent state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing. The adoption of future federal, state or local laws or implementing regulations imposing new environmental obligations on, or otherwise limiting, our operations could make it more difficult and more expensive to complete oil and natural gas wells, increase our costs of compliance and doing business, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products and services. We cannot assure you that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations.

Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in both the Rocky Mountains and Mid-Continent. In both the Rocky Mountains and the Mid-Continent, other companies in the oil and gas industry have significantly more experience than we do using hydraulic fracturing.

Typical hydraulic fracturing treatments are made up of water, chemical additives and sand. We utilize major hydraulic fracturing service companies who track and report all additive chemicals that are used in fracturing as required by the appropriate government agencies. Each of these companies fracture stimulate a multitude of wells for the industry each year. For as long as we have owned and operated properties subject to hydraulic fracturing, there have not been any material incidents, citations or suits related to fracturing operations or related to environmental concerns from fracturing operations.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. We adhere to applicable legal requirements and industry practices for groundwater protection. Our operations are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), who frequently inspect our fracturing operations.

We strive to minimize water usage in our fracture stimulation designs. Water recovered from our hydraulic fracturing operations is disposed of in a way that does not impact surface waters. We dispose of our recovered water by means of approved disposal or injection wells.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an Environmental Assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

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Oil Pollution Act

The Oil Pollution Act of 1990 (“OPA”) establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A “responsible party” under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

State laws

Our properties located in Colorado are subject to the authority of the Colorado Oil and Gas Conservation Commission (the “COGCC”), as well as other state agencies. The COGCC recently approved new rules regarding minimum setbacks and groundwater monitoring that are intended to prevent or mitigate environmental impacts of oil and gas development and include the permitting of wells. The COGCC also recently approved new rules regarding various other matters, including wellbore integrity, hydraulic fracturing, well control waste management and spill reporting. Depending on how these and any other new rules are applied, they could add substantial increases in well costs for our Colorado operations. The rules could also impact our ability and extend the time necessary to obtain drilling permits, which would create substantial uncertainty about our ability to meet future drilling plans and thus production and capital expenditure targets. The State of Colorado has also created a task force to make recommendations for minimizing land use and other conflicts concerning the location of new oil and gas facilities. In February 2015, the task force concluded their deliberations and agreed upon 9 consensus proposals which are being sent to Governor Hickenlooper for his review. Three of the proposals require further legislative action, while the other 6 proposals require rulemaking or other regulatory action.  The proposals support (i) a senate bill that would postpone expiration of recently adopted regulations, regarding air emissions; (ii) tasking the COGCC with crafting new rules related to siting of “large-scale” pads and facilities; (iii) requiring the industry to provide advance information about development plans to local governments; (iv) improving the COGCC’s local government liaison and designee programs; (v) adding 11 full-time staffers to the COGCC; (vi) bolstering the inspection staff and equipment for monitoring oil and gas facility air emissions and setting up a hotline for citizen health complaints at the Colorado Department of Public Health and Environment; (vii) creating a statewide oil and gas information clearinghouse; (viii) studying ways to ameliorate the impact of oil and gas truck traffic and (ix) creating a compliance-assistance program at the COGCC to help operators comply with the state's changing rules and ensure consistent enforcement of rules by state inspectors. A number of additional proposals did not receive sufficient task force support to be included with the 9 consensus proposals, but may nevertheless be forwarded to the Governor as well.

Employees

As of December 31, 2014, we employed 334 people and also utilize the services of independent contractors to perform various field and other services. 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.

Offices

As of December 31, 2014, we leased 83,165 square feet of office space in Denver, Colorado at 410 17th Street, where our principal offices are located and leased 1,635 square feet in Kersey, Colorado, where we have a field office. We also own field offices in Evans, Colorado, Stamps, Arkansas and Magnolia, Arkansas.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1 800 SEC 0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "BCEI." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.bonanzacrk.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website, other than the documents listed below, is not incorporated by reference into this Annual Report on Form 10 K.

Item 1A. Risk Factors.

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10 K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks Related to Our Business

A substantial or extended decline in oil and, to a lesser extent, natural gas prices, may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations or targets and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas and NGLs, heavily influences our revenue, profitability, cash flows, liquidity, borrowing base under our revolving credit facility, access to capital, present value and quality of our reserves, the nature and scale of our operations and future rate of growth. 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 oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 65% of our estimated proved reserves as of December 31, 2014 were oil and NGLs, our financial results are more sensitive to movements in oil prices. During fourth quarter 2014, a significant decline in crude oil prices occurred. As a result, we experienced decreases in crude oil revenues and recorded asset impairment charges due to commodity price declines. During the year ended December 31, 2014, the daily NYMEX WTI oil spot price ranged from a high of $107.26 per Bbl to a low of $53.27 per Bbl and the NYMEX natural gas HH spot price ranged from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu. As of February 23, 2015, the daily NYMEX WTI oil spot price and NYMEX natural gas HH spot price was $49.56 per Bbl and $3.22 per MMBtu, respectively.

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 oil and natural gas;

- the actions from members of the Organization of Petroleum Exporting Countries;

- the price and quantity of imports of foreign oil and natural gas;

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- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- the price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption;
- the availability of pipeline capacity and infrastructure; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-month) contracts at market based prices. Declines in commodity prices may have the following effects on our business:

- reduction of our revenues, profit margins, operating income and cash flows;
- reduction in the amount of crude oil, natural gas and NGLs that we can produce economically;
- certain properties in our portfolio becoming economically unviable;
- delay or postponement of some of our capital projects;
- further reduction of our 2015 capital program, or significant reductions in future capital programs, resulting in a reduced ability to develop our reserves;
- limitations on our financial condition, liquidity and/or ability to finance planned capital expenditures and operations;
- reduction to the borrowing base under our revolving credit facility or limitations in our access to sources of capital, such as equity or debt;

- declines in our stock price;
- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties (particularly with respect to our Mid-Continent acreage) at the date of assessment;
- additional counterparty credit risk exposure on commodity hedges; and
- reduction in the carrying value of goodwill.

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We are exposed to fluctuations in the price of oil and may be affected by continuing and prolonged declines in the price of oil and natural gas.

As of December 31, 2014, we had commodity price derivative agreements on approximately 9,985 Bbls/d and 5,500 Bbls/d of oil hedged with a combination of fixed price swaps and three-way collars during 2015 and 2016, respectively, and approximately 15,000 Mcf/d of natural gas hedged during 2015 with three-way collars. These commodity price derivatives represent approximately 60% of our anticipated production in 2015. These hedges may be inadequate to protect us from continuing and prolonged declines in the price of oil and natural gas. To the extent that the price of oil and natural gas remains at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges and our results of operations and financial condition would be negatively impacted.

In 2015, we have 6,251 Bbls/d of oil hedged with three-way collars with an average ceiling of $95.52/Bbl, average floor of $84.43/Bbl and average short floor of $68.20/Bbl. In 2015, we have 15,000 Mcf/d of natural gas hedged with three-way collars with an average ceiling of $4.75/Mcf, average floor of $4.00/Mcf and average short floor of $3.50/Mcf. In 2016, we have 5,500 Bbls/d of oil hedged with three-way collars with an average ceiling of $96.83/Bbl, average floor of $85.00/Bbl and average short floor of $70.00/Bbl. Currently, oil and natural gas prices are trading below the average prices of our short floors associated with our three-way collars. To the extent that future monthly settlement prices are below our short floor prices, we will realize the settlement price plus the difference between our short floor and floor prices. Therefore, additional risk is associated with these three-way collar contracts in a declining commodity price environment relative to fixed price swaps and collars. See the Derivative Activity section in Part I, Item I of this Annual Report on Form 10-K for a summary of our hedging activity.

Drilling for and producing 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 exploitation, exploration, development and production activities. Our 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 oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations 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. For a discussion of the uncertainty involved in these processes, see Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves below. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors, including the following factors, may result in substantial losses, including personal injury or loss of life, penalties, damage or destruction of property and equipment, and curtailments, delays or cancellations of our scheduled drilling projects:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- unanticipated environmental liabilities;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as blizzards, ice storms, tornadoes, floods, and fires;
- reductions in oil and natural gas prices;

- delays imposed by or resulting from compliance with regulatory requirements, such as permitting delays;
- proximity to and capacity of transportation facilities;
- title problems;
- safety concerns, and
- limitations in the market for oil and natural gas.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10 K. See Estimated Proved Reserves under Part I, Item 1 of this Annual Report on Form 10 K for information about our estimated oil and natural gas reserves and the PV 10 (a non GAAP financial measure) as of December 31, 2014, 2013 and 2012.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of these data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Although the reserve information contained herein is reviewed by independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise particularly as they relate to state-of-the-art technologies being employed such as the combination of hydraulic fracturing and horizontal drilling.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10 K and our impairment charges. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

There is a limited amount of production data from horizontal wells completed in the Wattenberg Field. As a result, reserve estimates associated with horizontal wells in this Field are subject to greater uncertainty than estimates associated with reserves attributable to vertical wells in the same Field.

Reserve engineers rely in part on the production history of nearby wells in establishing reserve estimates for a particular well or field. Horizontal drilling in the Wattenberg Field is a relatively recent development, whereas vertical drilling has been utilized by producers in this Field for over 50 years. As a result, the amount of production data from horizontal wells available to reserve engineers is relatively small. Until a greater number of horizontal wells have been completed in the Wattenberg Field, and a longer production history from these wells has been established, there may be a greater variance in our proved reserves on a year-over-year basis due to the transition from vertical to horizontal reserves in both the proved developed and proved undeveloped categories. We cannot assure you that any such variance would not be material and any such variance could have a material and adverse impact on our cash flows and results of operations. In addition, quantities of probable and possible reserves by definition are inherently more risky than proved reserves and are less likely to be recovered.

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Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the regions where we operate.

Oil and natural gas operations are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife, particularly in the Rocky Mountain region in both cases. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. These restrictions limit our ability to operate in those areas and can potentially intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Similarly, hot weather during some recent periods adversely impacted the transportation services provided by midstream companies, and therefore our production. Similar events could occur in the future and could negatively impact our results of operations and cash flows.

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 oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2014, 2013 and 2012, we based the estimated discounted future net revenues from our proved reserves on the unweighted arithmetic average of the first day of the month commodity prices (after adjustment for location and quality differentials) for the preceding twelve months, without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas and hedging instruments;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- the amount and timing of future development costs;
- the supply and demand of 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 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 (the factor required by the SEC) used 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 us or the oil and natural gas industry in general.

Because market prices for oil at the end of 2014 were significantly lower than the average price for the year determined under SEC rules, the actual future prices and costs will likely differ materially from those used in the present value estimates included in this Annual Report on Form 10 K. If oil and natural gas prices declined by 10% per Bbl and Mcf then our PV 10 as of December 31, 2014 would decrease by approximately 20% or $273.6 million. PV 10 is a non GAAP financial measure. Please refer to Estimated Proved Reserves under Part 1, Item 1 of this Annual Report on Form 10 K for management’s discussion of this non GAAP financial measure.

Depressed oil and natural gas prices could require us to take write downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans,

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production data, economics and other factors, from time to time, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We recorded a $167.6 million impairment of oil and gas properties for the year ended December 31, 2014, primarily due to depressed commodity prices. Additionally, we may incur significant 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.

We intend to pursue the further development of our properties in the Wattenberg Field through horizontal drilling. Horizontal drilling operations can be more operationally challenging and costly relative to our historic vertical drilling operations. Our limited operational history with drilling and completing horizontal wells may make us more susceptible to cost overruns and lower results.

Horizontal drilling is generally more complex and more expensive on a per well basis than vertical drilling. As a result, there is greater risk associated with a horizontal well drilling program. Risks associated with our horizontal drilling program include, but are not limited to, the following, any of which could materially and adversely impact the success of our horizontal drilling program and thus, our cash flows and results of operations:

- landing our well bore in the desired drilling zone;
- effectively controlling the level of pressure flowing from particular wells;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the well bore;
- being able to run tools and other equipment consistently through the horizontal well bore;
- being able to fracture stimulate the planned number of stages;
- preventing downhole communications with other wells;
- successfully cleaning out the well bore after completion of the final fracture stimulation stage; and
- designing and maintaining efficient forms of artificial lift throughout the life of the well.

The results of our drilling in new or emerging formations, such as horizontal drilling in the Niobrara formation, are more uncertain initially than drilling results in areas or using technologies that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history, and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, limited takeaway capacity, or depressed natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments, we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

Our ability to produce natural gas and oil economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracture stimulation process on which we depend to produce commercial quantities of oil and natural gas requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Compliance with environmental

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regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, and all of which could have an adverse effect on our operations and financial condition.

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 our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves or anticipated production volumes.

Our exploration, development and exploitation activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Our cash flows used in investing activities, excluding derivative cash settlements, were $837.2 million, of which, $832.8 million (including $191.6 million for the acquisition of oil and gas properties and contractual obligations for land acquisitions) related to capital and exploration expenditures for the year ended December 31, 2014. Our capital expenditure budget for 2015 is approximately $420 million, with approximately $380 million allocated for operated drilling and completion activities. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

A significant improvement in oil and gas prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flows provided by operating activities and borrowings under our revolving credit facility. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional equity securities, debt securities or the strategic sale of assets. The issuance of additional debt may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under our revolving credit facility would be reduced. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under our revolving credit facility or our revenues decrease as a result of lower 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 on terms favorable to us, or at all. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

Increased costs of capital could adversely affect our business.

Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability, impacting our ability to finance our operations. Our business and operating results can be harmed by factors such as the terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage.

We may experience difficulty in achieving and managing future growth.

We have experienced growth in the past primarily through the expansion of our drilling program and acquisitions. Our ability to grow depends on a number of factors, including:

· our ability to obtain leases or options on properties, including those for which we have 3 D seismic data;
· our ability to identify and acquire new exploratory prospects;
· our ability to develop existing prospects;
· our ability to continue to retain and attract skilled personnel;
· our ability to maintain or enter into new relationships with project partners and independent contractors;
· the results of our drilling program;
· oil and natural gas prices; and
· our access to capital.

Future growth may place strains on our financial, technical, operational and administrative resources and cause us to rely more on project partners and independent contractors, possibly negatively affecting our financial position and results of operations. Our inability to achieve or manage growth may adversely affect our financial position and results of operations.

Our ability to pursue our growth strategy may be hindered if we are not able to attract, develop and retain executives and other qualified employees. As a result, we are required to continue to invest in operational, financial and management information systems to attract, retain, motivate and effectively manage our employees.

Concentration of our operations in a few core areas may increase our risk of production loss.

Our assets and operations are concentrated in two core areas: the Wattenberg Field in Colorado and the Dorcheat Macedonia Field in southern Arkansas. These core areas currently provide approximately 99% of our current sales volumes and the vast majority of our development projects. Beginning in 2012, we initiated a non core divestiture program to focus our portfolio through the sale of certain non core assets in California. This program was completed in the first quarter of 2014 when we sold our last asset in California. As a result of these portfolio changes, our operations and production are more concentrated.

The Wattenberg and Dorcheat Macedonia Fields represent 75% and 24%, respectively, of our 2014 total sales volumes. Because our operations are not as diversified geographically as some of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including: fluctuations in prices of crude oil, natural gas and NGLs produced from wells in the area, accidents or natural disasters, restrictive governmental regulations and curtailment of production or interruption in the availability of gathering, processing or transportation infrastructure and services, and any resulting delays or interruptions of production from existing or planned new wells. For example, recent increases in activity in the Wattenberg Field have contributed to bottlenecks in processing and transportation that have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules, that could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field, we are subject to increasing competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages or delays. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

We do not maintain business interruption (loss of production) insurance for our oil and gas producing properties. Loss of production or limited access to reserves in either of our core operating areas could have a significant negative impact on our cash flows and profitability.

We are dependent on third party pipeline, trucking and rail systems to transport our production and, in the Wattenberg Field, gathering and processing systems to prepare our production. These systems have limited capacity and at times have experienced service disruptions. Curtailments, disruptions or lack of availability in these systems interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production getting to market. The marketability of our oil and natural gas and production, particularly from our wells located in the Wattenberg Field, depends in part on the availability, proximity and capacity of gathering, processing, pipeline, trucking and rail systems. The amount of oil and natural gas that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, excessive pressures, maintenance, weather, field labor issues or disruptions in service. Curtailments and disruptions in these systems may last from a few days to several months. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. These risks are greater for us than for some of our competitors because our operations are focused on areas where there is currently a substantial amount of development activity, which increases the likelihood that there will be periods of time in which there is insufficient midstream capacity to accommodate the resulting increases in production. For example, in 2014, the principal third-party provider we use in the Wattenberg Field experienced periods of high line pressures and was forced to periodically shut down due to oxygen in the line and for other unscheduled repairs. The resulting capacity constrained our production and reduced our revenue from the affected wells. In addition, we might voluntarily curtail production in response to market conditions. Any significant curtailment in gathering, processing or pipeline system capacity, significant delay in the construction of necessary facilities or lack of availability of transport, would interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations, and the expected results of our drilling program.

Currently, there are no natural gas pipeline systems that service wells in the North Park Basin, which is prospective for the Niobrara formation. In addition, we are not aware of any plans to construct a facility necessary to process natural gas produced from this basin. If neither we nor a third party constructs the required pipeline system and processing facility, we may not be able to fully develop our resources in the North Park Basin.

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

Approximately 48% of our total proved reserves were classified as proved undeveloped as of December 31, 2014. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our current proved reserves will decline as reserves are produced and, therefore, our level of production and cash flows will be affected adversely unless we conduct successful exploration and development activities or acquire properties containing proved reserves. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding or acquiring additional reserves. However, we cannot assure you that our future acquisition, development and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

According to estimates included in our December 31, 2014 proved reserve report, if, on January 1, 2015, we had ceased all drilling and development, including recompletions, refracs and workovers, then our proved developed producing reserves base would decline at an annual effective rate of 45% during the first year. If we fail to replace reserves through drilling, our level of production and cash flows will be affected adversely.

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

Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including, but not limited to, the possibility of:

· environmental hazards, such as spills, uncontrollable flows of oil, natural gas, brine, well fluids, natural gas, hazardous air pollutants or other pollution into the environment, including groundwater and shoreline contamination;
· releases of natural gas and hazardous air pollutants or other substances into the atmosphere (including releases at our gas processing facilities);
· hazards resulting from the presence of hydrogen sulfide ($H_2S$) or other contaminants in natural gas we produce;
· abnormally pressured formations resulting in well blowouts, fires or explosions;
· mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
· cratering (catastrophic failure);
· downhole communication leading to migration of contaminants;
· personal injuries and death; and

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· natural disasters.

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 and 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.

The presence of $H_2S$, a toxic, flammable and colorless gas, is a common risk in the oil and gas industry and may be present in small amounts for brief periods from time to time at our well locations. Additionally, at two of our Arkansas properties, we produce a small amount of gas from seven operated wells where we have identified the presence of $H_2S$ at levels that would be hazardous in the event of an uncontrolled gas release or unprotected exposure. In addition, our operations in Arkansas and Colorado are susceptible to damage from natural disasters such as flooding, wildfires or tornados, which involve increased risks of personal injury, property damage and marketing interruptions. The occurrence of one of these operating hazards may result in injury, loss of life, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration and development, or could result in a loss of our properties.

As is customary in the oil and gas industry, we maintain insurance against some, but not all, of these potential risks and losses. Although we believe the coverage and amounts of insurance that we carry are consistent with industry practice, we do not have insurance protection against all risks that we face, because we choose not to insure certain risks, insurance is not available at a level that balances the costs of insurance and our desired rates of return, or actual losses exceed coverage limits. Insurance costs will likely continue to increase which could result in our determination to decrease coverage and retain more risk to mitigate those cost increases. In addition, pollution and environmental risks generally are not fully insurable. If we incur substantial liability, and the damages are not covered by insurance or are in excess of policy limits, then our business, results of operations and financial condition may be materially adversely affected.

Because hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if the operator is unaware of the pollution event and unable to report the "occurrence" to the insurance company within the required time frame. Nor do we have coverage for gradual, long term pollution events.

Under certain circumstances, we have agreed to indemnify third parties against losses resulting from our operations. Pursuant to our surface leases, we typically indemnify the surface owner for clean up and remediation of the site. As owner and operator of oil and gas wells and associated gathering systems and pipelines, we typically indemnify the drilling contractor for pollution emanating from the well, while the contractor indemnifies us against pollution emanating from its equipment.

Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10 K. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional evaluation. There is no way to predict in advance of drilling and

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testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. Prior to drilling, the use of 2-D and 3-D seismic technologies, various other technologies and the study of producing fields in the same area will not enable us to know conclusively whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. In addition, the use of 2-D and 3-D seismic data and other technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures which may result in a reduction in our returns or increase our losses. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill any dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our potential drilling locations are scheduled to be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including uncertainty in the level of reserves, the availability of capital to us and other participants, seasonal conditions, regulatory approvals, oil and natural gas prices, availability of permits, costs and drilling results. 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 oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking, and we may therefore be required to downgrade to probable or possible any proved undeveloped reserves that are not developed within this five-year time frame. These limitations may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

The terms of our oil and gas leases stipulate that the lease will terminate if not held by production, rentals, or operations. As of the filing date of this report, the majority of our acreage in Arkansas was held by unitization, production, or drilling operations and therefore not subject to lease expiration. As of the filing date of this report, approximately 18,704 net acres of our properties in the Rocky Mountain region were not held by production. For these properties, if production in paying quantities is not established on units containing these leases during the next year, then approximately 12,717 net acres will expire in 2015, approximately 5,110 net acres will expire in 2016, and approximately 876 net acres will expire in 2017 and thereafter. While some expiring leases may contain predetermined renewal payments, other expiring leases will require us to negotiate new leases at the time of lease expiration. It is possible that market conditions at the time of negotiation could require us to agree to new leases on less favorable terms to us than the terms of the expired leases.If our leases expire, we will lose our right to develop the related properties.

We may incur losses as a result of title deficiencies.

The existence of a title deficiency can diminish the value of an acquired leasehold interest and can adversely affect our results of operations and financial condition. Title insurance covering mineral leasehold interests is not generally available. In certain situations, we may rely upon a land professional's careful examination of public records prior to purchasing or leasing a mineral interest. Once a specific mineral or leasehold interest has been acquired, we typically defer the expense of obtaining further title verification by a practicing title attorney until approval to drill the related drilling block is required. We do not always perform curative work to correct deficiencies in the marketability of

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the title; however, we currently have compliance and control measures to ensure any associated business risk is approved by the appropriate Company authority. In cases involving more serious title deficiencies, all or part of a mineral or leasehold interest may be determined to be invalid or unleased, and, as a result, the target area may be deemed to be undrillable until owners can be contacted and curative measures performed to perfect title. In other cases, title deficiencies may result in our failure to have paid royalty owners correctly. Certain title deficiencies may also result in litigation from time to time. Additional title issues are present in our southern Arkansas operations where significant delays in the title examination process are possible due to, among other challenges, the large volume of instruments contained in abstracts, poor indexing at the county clerk and recorder's office, misfiling of instruments, instruments with missing or inadequate legal descriptions and unclear conveyance terms.

Acquisitions of properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.

Acquisitions of producing properties and undeveloped properties have been an important part of our recent and historical growth. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future commodity prices, operating costs, title issues and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform engineering, environmental, geological and geophysical reviews of the acquired properties, which we believe are generally consistent with industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may not always discover structural, subsurface and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, from time to time we also acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. Often we are not entitled to contractual indemnification associated with acquired properties. In certain cases, we acquire interests in properties on an "as is" basis with no or limited remedies for breaches of representations and warranties. Therefore, we could incur significant unknown liabilities, including environmental liabilities, or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

Furthermore, significant acquisitions could change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or may be in different geographic locations than our existing properties. These factors can increase the risks associated with an acquisition. Acquisitions also present risks associated with the additional indebtedness that may be required to finance the purchase price, and any related increase in interest expense or other related charges.

We face various risks associated with the trend toward increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non governmental organizations regarding safety, environmental compliance and business practices. Anti development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil or gas shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling in the United States, even in jurisdictions that are among the most stringent in their regulation of the industry. In fact, New York State has just enacted a permanent moratorium on all hydraulic fracturing operations. Future activist efforts could result in the following:

· delay or denial of drilling permits;

- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of production, gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposal of related waste materials, such as hydraulic fracturing fluids and produced water;
- increased severance and/or other taxes;
- cyber attacks;
- legal challenges or lawsuits;
- negative publicity about us or the oil and gas industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

We may need to incur significant costs associated with responding to these initiatives. Complying with any resulting additional legal or regulatory requirements that are substantial could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to health, safety and environmental laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration, production and processing operations are subject to stringent and complex federal, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment and the protection of the environment. These laws and regulations may impose on our operations numerous requirements, including the obligation to obtain a permit before conducting drilling or underground injection activities; restrictions on the types, quantities and concentration of materials that may be released into the environment; limitations or prohibitions of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria to protect workers; and the responsibility for cleaning up any pollution resulting from operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our operations; delays in granting permits, or even the cancellation of leases.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions into air and water, the underground injection or other disposal of our wastes, the use and disposition of hydraulic fracturing fluids, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable for the full cost of removing or remediating contamination, regardless of whether we were at fault, and even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws. In addition, accidental spills or releases on our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Aside from government agencies, the owners of properties where our wells are located, the operators of facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, collect penalties for violations or obtain damages for any related personal injury or

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property damage. Some sites we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that historic contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, emission, waste management or cleanup requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

New environmental legislation or regulatory initiatives, including those related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.

We are subject to extensive federal, state, and local laws and regulations concerning health, safety, and environmental protection. Government authorities frequently add to those requirements, and both oil and gas development generally, and hydraulic fracturing specifically, are receiving increasing regulatory attention. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

In August 2012, the EPA issued final New Source Performance Standards (known as “Quad O”) that establish new air emission controls for natural gas processing operations, as well as for oil and natural gas production. Among other things, Quad O imposes reduced emission completion (or “green completion”) requirements and also imposes stringent control and other standards on certain storage tanks, compressors and associated equipment. After several parties challenged the Quad O regulations in court, the EPA administratively reconsidered certain requirements. As a result of such administrative reconsideration, the EPA issued final amendments to the Quad O regulations in September 2013 and December 2014, and is evaluating whether further reconsideration is warranted. At this point, we cannot predict the final regulatory requirements or the cost to comply with such air regulatory requirements.

On December 17, 2014, the EPA proposed to revise and lower the existing 75 ppb NAAQS for ozone under the federal Clean Air Act to a range within 65-70 ppb. The EPA is also taking public comment on whether the ozone NAAQS should be revised as low as 60 ppb. A lowered ozone NAAQS in a range of 60-70 ppb could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. In addition, in February 2014, the Colorado Department of Public Health and Environment’s Air Quality Control Commission finalized regulations imposing stringent new requirements relating to air emissions from oil and gas facilities in Colorado that are even more stringent than comparable federal rules. These new Colorado rules include storage tank control, monitoring, recordkeeping and reporting requirements as well as leak detection and repair requirements for both well production facilities and compressor stations and associated equipment. These new requirements, which represent the first time a state has directly regulated methane (a greenhouse gas) emissions from the upstream oil and gas sector, have and will continue to impose additional costs on our operations.

Some activists have attempted to link hydraulic fracturing to various environmental problems, including potential adverse effects to drinking water supplies as well as migration of methane and other hydrocarbons. As a result, the federal government is studying the environmental risks associated with hydraulic fracturing and evaluating whether to adopt additional regulatory requirements. For example, the EPA has commenced a multi year study of the potential impacts of hydraulic fracturing on drinking water resources. A draft of this report is expected in 2015 and a final, peer reviewed report is expected in 2016. In addition, in 2011, the EPA announced its intention to propose regulations under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. Proposed rules are expected in early 2015. The EPA also has issued guidance for issuing underground injection permits for hydraulic fracturing operations that use diesel fuel under the agency’s Safe Drinking Water Act

(“SDWA”) authority. This guidance could encourage other regulatory authorities to adopt more stringent to permitting and other restrictions on the use of hydraulic fracturing. The U.S. Department of the Interior, moreover, has proposed new rules for hydraulic fracturing activities on federal lands that, in general, would cover disclosure of fracturing fluid components, well bore integrity, and handling of flowback water. The rule is in its final stages and the BLM is expected to issue a final rule in 2015. The BLM is also expected to consider implementing rules addressing venting and flaring on

BLM land. And the U.S. Occupational Safety and Health Administration has proposed stricter standards for worker exposure to silica, which would apply to use of sand as a proppant for hydraulic fracturing.

In the United States Congress, bills have been introduced that would amend the SDWA to eliminate an existing exemption for certain hydraulic fracturing activities from the definition of “underground injection,” thereby requiring the oil and natural gas industry to obtain SDWA permits for fracturing not involving diesel fuels, and to require disclosure of the chemicals used in the process. If adopted, such legislation could establish an additional level of regulation and permitting at the federal level, but some form of chemical disclosure is already required by most oil and gas producing states. At this time, it is not clear what action, if any, the United States Congress will take on hydraulic fracturing.

Apart from these ongoing federal initiatives, state governments where we operate have moved to impose stricter requirements on hydraulic fracturing and other aspects of oil and gas production. Colorado, for example, comprehensively updated its oil and gas regulations in 2008 and adopted significant additional amendments in 2011 and 2014. Among other things, the updated and amended regulations require operators to reduce methane emissions associated with hydraulic fracturing, compile and report additional information regarding well bore integrity, publicly disclose the chemical ingredients used in hydraulic fracturing, increase the minimum distance between occupied structures and oil and gas wells, undertake additional mitigation for nearby residents, implement additional groundwater testing and incur increased monetary penalties for violations of the State’s oil and gas conservation commission rules and regulations. Similarly, in February 2015, a task force created by the State of Colorado aimed at making recommendations for minimizing land use and other conflicts concerning the location of new oil and gas facilities agreed upon 9 consensus proposals which are being sent to Governor Hickenlooper for his review. Three of the proposals require further legislative action, while the other 6 proposals require rulemaking or other regulatory action. The proposals support (i) a senate bill that would postpone expiration of recently adopted regulations regarding air emissions; (ii) tasking the COGCC with crafting new rules related to siting of “large-scale” pads and facilities; (iii) requiring the industry to provide advance information about development plans to local governments; (iv) improving the COGCC’s local government liaison and designee programs; (v) adding 11 full-time staffers to the COGCC to improve inspections and field operations; (vi) bolstering the inspection staff and equipment for monitoring oil and gas facility air emissions and setting up a hotline for citizen health complaints at the Colorado Department of Public Health and Environment; (vii) creating a statewide oil and gas information clearinghouse; (viii) studying ways to ameliorate the impact of oil and gas truck traffic and (ix) creating a compliance-assistance program at the COGCC to help operators comply with the state's changing rules and ensure consistent enforcement of rules by state inspectors. A number of additional proposals did not receive sufficient task force support to be included with the 9 consensus proposals, but may nevertheless be forwarded to the Governor as well.

Even local governments are adopting new requirements on hydraulic fracturing and other oil and gas operations. Some counties in Colorado, for instance, have amended their land use regulations to impose new requirements on oil and gas development, while other local governments have entered memoranda of agreement with oil and gas producers to accomplish the same objective. Voters in the cities of Fort Collins, Boulder and Lafayette, Colorado recently approved bans of varying length on hydraulic fracturing within their respective city limits. The bans in Longmont, Lafayette and Fort Collins were overturned by local district courts; the Boulder and Broomfield bans remain in place and the Boulder County moratorium was recently extended until 2018. The Longmont City Council has appealed the district court’s decision to overturn the ban and Fort Collins is appealing that court decision as well. While these initiatives cover areas with little recent or ongoing oil and gas development, they could lead opponents of hydraulic fracturing to push for statewide referendums, especially in Colorado. For example, in the wake of successful local bans, the State of New York recently placed a permanent moratorium on all hydraulic fracturing operations within the state.

The adoption of future federal, state or local laws or implementing regulations imposing new environmental obligations on, or otherwise limiting, our operations could make it more difficult and more expensive to complete oil and natural gas wells, increase our costs of compliance and doing business, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products and services. We cannot assure you that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

There is a growing belief that human caused (anthropogenic) emissions of greenhouse gases ("GHGs") may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services and the demand for and consumption of our products and services (due to potential changes in both costs and weather patterns).

In December 2009, the EPA determined that atmospheric concentrations of carbon dioxide, methane and certain other GHGs present an endangerment to public health and welfare, because such gases are, according to the EPA, contributing to the warming of the Earth's atmosphere and other climatic changes. Consistent with its findings, the EPA has proposed or adopted various regulations under the Clean Air Act to address GHGs. Among other things, the EPA began limiting emissions of GHGs from new cars and light duty trucks beginning with the 2012 model year. In addition, in 2010 the EPA published a final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or "PSD," and Title V permitting programs. Under this rule, the EPA imposed certain GHG permitting requirements on the largest major sources first. As noted above, in June 2014, the United States Supreme Court invalidated part of the EPA's stationary source GHG program in Utility Air Regulatory Group v. EPA, No. 12-1146. Specifically, the Supreme Court ruled that major sources subject to the PSD or Title V programs because of non-GHG emissions could potentially be still subject to certain "best available control technology" requirements applicable to their GHG emissions. Under the Supreme Court's opinion, sources subject to the PSD or Title V programs due solely to their GHG emissions can no longer be subject to EPA's GHG permitting requirements. The EPA also adopted regulations requiring the reporting of GHG emissions from specific categories of higher GHG emitting sources in the United States, including certain oil and natural gas production facilities, which include certain of our operations, beginning in 2012 for emissions occurring in 2011. Information in such report may form the basis for further GHG regulation. Further, the EPA has announced a comprehensive strategy for further reducing methane emissions from oil and gas operations, with a proposed rule expected in 2015 and a final rule in 2016. The EPA's GHG rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

Moreover, Congress has from time to time considered adopting legislation to reduce emissions of GHGs or promote the use of renewable fuels. As an alternative, some proponents of GHG controls have advocated mandating a national "clean energy" standard. In 2011, for example, President Obama encouraged Congress to adopt a goal of generating 80% of U.S. electricity from "clean energy" by 2035 with credit for renewable and nuclear power and partial credit for clean coal and "efficient natural gas." In the absence of such a comprehensive federal legislative program expressly addressing GHGs, the EPA recently proposed rules known as the "Clean Power Plan" designed to decrease GHG emissions, primarily from electric generating power plants. A final rule for both new and existing power plants under the Clean Power Plan is expected in 2015. We are unable to predict how, or if, the Clean Power Plan will affect our operations.

In the meantime, many states already have taken such measures, which have included renewable energy standards, development of GHG emission inventories or cap and trade programs. Cap and trade programs typically work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of available allowances reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms and floods. If any such effects were to occur, they could have an adverse effect on our exploration and production operations. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. Our insurance may not cover some or any of the damages, losses, or costs that may result from potential physical effects of climate change.

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

Our ability to acquire additional drilling locations 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 oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. 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 over the past few 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 business.

If we fail to retain our existing senior management or technical personnel or attract qualified new personnel, such failure could adversely affect our operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management, technical personnel, or any of the vice presidents of the Company, could have a material adverse effect on our operations. Furthermore, competition for experienced senior management, technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We recorded substantial stock based compensation expense in 2014, and we are likely to incur additional stock based compensation expense related to our future grants of stock, which may impact our operating results for the foreseeable future.

We incurred stock based compensation expense in 2014 in the amount of $20.7 million, of which $7.6 million related to executive departures, compared to $12.6 million in 2013. Our compensation expenses are likely to increase in the future as compared to our historical expenses because of the costs associated with our stock based incentive plans. These additional expenses will adversely affect our net income. We cannot determine the actual amount of these new stock related compensation and benefit expenses at this time, because applicable accounting practices generally require that they be based on the fair market value of the options or shares of common stock at the date of the grant; however, we expect them to be significant. We will recognize expenses for restricted stock and stock option awards we grant generally over the vesting period of such awards.

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

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

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

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd Frank Act, which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over the counter derivatives market and entities that participate in that market. The Dodd Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. On October 18, 2011, the Commodities Futures Trading Commission (the "CFTC") approved regulations to set position limits for certain futures and option contracts in the major energy markets, which were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC has filed a notice of appeal with respect to this ruling. Under CFTC final rules promulgated under the Dodd Frank Act, we believe our derivatives activity will qualify for the non financial, commercial end user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement. The Dodd Frank Act may also require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd Frank Act and any 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 our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative as a result of the Dodd Frank Act and regulations, our results of operations may be more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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Our leverage and debt service obligations may adversely affect our financial condition, results of operations, business prospects and our ability to make payment on our Senior Notes.

As of December 31, 2014, we had $500 million of outstanding 6.75% Senior Notes due 2021 ("6.75% Senior Notes"), $300 million of outstanding 5.75% Senior Notes due 2023 ("5.75% Senior Notes" and, together with the 6.75% Senior Notes, the "Senior Notes"), $33 million outstanding under our revolving credit facility and $2.6 million of cash and cash equivalents. We intend to fund our capital expenditures through our cash flow from operations and borrowings under our revolving credit facility, but may seek additional debt financing. Our level of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;
- limit management's discretion in operating our business and our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then outstanding bank borrowings;
- make us more vulnerable to increases in interest rates as our indebtedness under any revolving credit facility may vary with prevailing interest rates;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- make it more difficult for us to satisfy our obligations under the Senior Notes or other debt and increase the risks that we may default on our debt obligations.

Our revolving credit facility and the indentures governing the Senior Notes have restrictive covenants that could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our revolving credit facility and the indentures governing the Senior Notes contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests.

Our ability to borrow under our revolving credit facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio, a maximum leverage ratio and a minimum interest coverage ratio.

In addition, our revolving credit facility and the indentures governing the Senior Notes contain covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to:

- incur or guarantee additional indebtedness;

- issue preferred stock;
- sell or transfer assets;
- pay dividends on, redeem or repurchase our capital stock;
- repurchase or redeem our subordinated debt;
- make certain acquisitions and investments;
- create or incur liens;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- enter into sale leaseback transactions;
- consolidate, merge or transfer all or substantially all of our assets; and
- engage in certain business activities.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We would not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants contained in our revolving credit facility and the indentures governing the Senior Notes. Our ability to comply with the financial ratios and financial condition tests under our revolving credit facility may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities.

Borrowings under our revolving credit facility are limited by our borrowing base, which is subject to periodic redetermination.

The borrowing base under our revolving credit facility is redetermined at least semi-annually, and up to one additional time between scheduled determinations upon request of the Company or lenders holding $66^{2}/_{3}\%$ of the aggregate commitments. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors. Upon a redetermination, we could be required to repay a portion of our bank debt to the extent our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

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The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates. We had approximately $54.6 million in receivables from oil and gas sales at December 31, 2014.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2014, sales to Plains Marketing LP, Lion Oil Trading & Transport, Inc. and High Sierra Crude Oil & Marketing accounted for approximately 29%, 19% and 11%, respectively, of our total sales. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

We may be involved in legal proceedings that may result in substantial liabilities.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

We are subject to federal, state, and local taxes, and may become subject to new taxes and certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell, and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons and additional increases may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals.

There have been proposals for legislative changes that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. Any such changes in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations and cash flow.

Changes to federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including production, severance or similar taxes) could negatively affect our financial condition and results of operations.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation and process and record financial and operating data. Pipelines, refineries, power stations and distribution points for both fuels and electricity are becoming more interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. Our technologies, systems, networks and those of our vendors, suppliers and other business partners may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Given the politically sensitive nature of hydraulic fracturing and the controversy generated by its opponents, our technologies, systems and networks may be of particular interest to certain groups with political agendas, which may seek to launch cyber attacks as a method of promoting their message. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient.

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, communicate with our employees and business parties, analyze seismic and drilling information, estimate quantities of oil and gas reserves as well as other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production and financial institutions, are also dependent on digital technology. The technologies needed to conduct our oil and gas exploration and development activities make certain information the target of theft or misappropriation.

Although to date we have not experienced any material losses relating to cyber attacks, we may suffer such losses in the future. 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.

Risks Relating to our Common Stock

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, our stockholders' only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our revolving credit facility and our Senior Notes. Consequently, our stockholders' only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the stockholders sell their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the stockholders paid.

The market price and trading volume of our common stock may be volatile and our stock price could decline.

The trading price of shares of our common stock has from time to time fluctuated widely and in the future may be subject to similar fluctuations. As an example, during the year ended December 31, 2014, the sales price of our common stock ranged from a low of $16.36 per share to a high of $62.94 per share. The trading price of our common stock may be affected by a number of factors, including the volatility of oil and natural gas prices, our operating results, changes in our earnings estimates, additions or departures of key personnel, our financial condition, drilling activities, legislative and regulatory changes, general conditions in the oil and natural gas exploration and development industry, general economic conditions, and general conditions in the securities markets. In particular, a significant or extended decline in oil and natural gas prices could have a material adverse effect our sales price of our common stock. Other risks described in this annual report could also materially and adversely affect our share price.

Although our common stock is listed on the New York Stock Exchange, we cannot assure you that an active public market will continue for our common stock. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock

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market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us.

Future sales of our common stock in the public market could lower our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute our current stockholders' ownership in us.

If our existing stockholders sell a large number of shares of our common stock in the public market, the market price of our common stock could decline significantly. In addition, the perception in the public market that our existing stockholders might sell shares of common stock could depress the market price of our common stock, regardless of the actual plans of our existing stockholders. Her Majesty the Queen in Right of Alberta, in her own capacity and as trustee/nominee for certain Alberta pension clients ("HMQ"), owns 7,587,859 shares, or approximately 15% of our total outstanding shares. HMQ is party to a registration rights agreement with us (the "HMQ Registration Rights Agreement"). Pursuant to the HMQ Registration Rights Agreement, we have agreed to effect the registration of shares held by HMQ if it so requests or if we conduct other registrations of our common stock. In addition, we may issue additional shares of our common stock, including securities that are convertible into or exchangeable for, or that represent the right to receive, shares of common stock or substantially similar securities, which may result in dilution to our stockholders. In addition, our stockholders may be further diluted by future issuances under our equity incentive plans.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders' best interests.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified board of directors, so that only approximately one third of our directors are elected each year;
- advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders; and
- limitations on the ability of our stockholders to call special meetings or act by written consent.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors.

Alberta Investment Management Corporation ("AIMCO") may be deemed to beneficially own or control 15% of our common stock, potentially giving it influence over corporate transactions and other matters. Its interests and the interests of the parties on whose behalf it invests may conflict with our other stockholders, and the concentration of ownership of our common stock by such stockholders will limit the influence of other public stockholders.

AIMCo, a Canadian corporation and investment manager to HMQ and certain Alberta pension funds, may be deemed to beneficially own, control or have influence over approximately 15% of our outstanding common stock. West Face Capital and AIMCo, on behalf of HMQ and certain Alberta pension funds, have entered into an investment management agreement pursuant to which West Face Capital has the right to vote the shares of our common stock held by HMQ. Accordingly, West Face may attempt to exert influence over our board of directors and the outcome of stockholder votes. Even if the investment management agreement between West Face Capital and AIMCo were to be terminated, AIMCo, on behalf of HMQ, could have the ability to exert influence over the Company. Other than the

HMQ Registration Rights Agreement, there are no contractual relationships or other understanding between the Company and HMQ or AIMCo.

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A concentration of beneficial ownership in AIMCo or West Face Capital could allow such stockholders to influence, directly or indirectly and subject to applicable law, significant matters affecting us, including the following:

· establishment of business strategy and policies;
· amendment of our certificate of incorporation or bylaws;
· nomination and election of directors;
· appointment and removal of officers;
· our capital structure; and
· compensation of directors, officers and employees and other employee related matters.

Such a concentration of ownership may have the effect of delaying, deterring or preventing a change in control, a merger, consolidation, takeover or other business combination, and could discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of us, which could in turn have an adverse effect on the market price of our common stock.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

The information required by Item 2. is contained in Item 1. Business and is incorporated herein by reference.

Item 3. Legal Proceedings.

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As of the date of this filing, there are no material pending or overtly threatened legal actions against us that of which we are aware.

Item 4. Mine Safety Disclosures.

Not applicable.

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PART II

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

Market for Registrant’s Common Equity. Our common stock is listed on the NYSE under the symbol “BCEI”. On February 24, 2015, the sale price of our common stock, as reported on the NYSE, was $29.03 per share.

The following table sets forth the high and low intra day sales prices per share of our common stock as reported on the NYSE.

| | High | Low |
|---|---|---|
| 2013 | | |
| 1st Quarter | $ 42.36 | $ 28.23 |
| 2nd Quarter | 40.40 | 32.06 |
| 3rd Quarter | 51.32 | 34.67 |
| 4th Quarter | 57.47 | 41.78 |
| 2014 | | |
| 1st Quarter | $ 52.47 | $ 37.71 |
| 2nd Quarter | 62.94 | 41.08 |
| 3rd Quarter | 62.89 | 53.75 |
| 4th Quarter | 57.12 | 16.36 |

Holders. As of February 24, 2015, there were approximately 235 registered holders of our common stock.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility and the indentures governing our Senior Notes restrict the payment of cash dividends on our common stock. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the quarter ended December 31, 2014.

| | Total Number of Shares Purchased(1) | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plan or Program | Maximum Number of Shares that May Be Purchased Under Plans or Programs |
|---|---|---|---|---|
| October 1, 2014 - October 31, 2014 | 2,645 | $ 35.56 | — | — |
| November 1, 2014 - November 30, 2014 | 4,928 | $ 39.11 | — | — |
| December 1, 2014 - December 31, 2014 | 12,236 | $ 21.84 | — | — |
| Total | 19,809 | $ 27.97 | — | — |

(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced plan or program to repurchase shares of our common stock, nor do we have a publicly announced plan or program to repurchase shares of our common stock.

Sale of Unregistered Securities. We had no sales of unregistered securities during the quarter ended December 31, 2014.

Stock Performance Graph. The following performance graph shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to liabilities under that section and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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The following graph compares the cumulative total stockholder return for the Company's common stock, the Standard and Poor's 500 Stock Index (the "S&P 500 Index") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P Index"). The measurement points in the graph below are December 14, 2011 (the first trading day of our common stock on the NYSE) and each fiscal quarter thereafter through December 31, 2014. The graph assumes that $100 was invested on December 14, 2011 in each of the common stock of the Company, the S&P 500 Index and the S&P O&G E&P Index and assumes reinvestment of any dividends. The stock price performance on the following graph is not necessarily indicative of future stock price performance.

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Item 6. Selected Financial Data.

The selected historical financial data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations below and financial statements and the notes to those financial statements in Part I, Item 8 of this Annual Report on Form 10 K.

The following tables set forth selected historical financial data of the Company as of and for the period indicated.

| | For the Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2010 | 2011 | 2012 | 2013 | 2014 |
| | (in thousands, except per share amounts) | | | | |
| Statement of Operations Data: | | | | | |
| Total operating net revenues (1) | $ 1,620 | $ 105,724 | $ 231,205 | $ 421,860 | $ 558,633 |
| Income (loss) from operations (1) | 375 | 34,425 | 77,903 | 146,995 | (47,506) |
| Net income (loss) | (162) | 12,691 | 46,523 | 69,184 | 20,283 |
| Basic net income per common share | $ — | $ 0.43 | $ 1.17 | $ 1.72 | $ 0.50 |
| Basic weighted-average common shares outstanding | 29,123 | 29,324 | 39,052 | 39,337 | 40,139 |
| Diluted net income per common share | $ — | $ 0.43 | $ 1.17 | $ 1.71 | $ 0.49 |
| Diluted weighted-average commons shares outstanding | 29,123 | 29,324 | 39,052 | 39,403 | 40,290 |
| Balance Sheet Data: | | | | | |
| Cash and cash equivalents | $ — | $ 2,090 | $ 4,268 | $ 180,582 | $ 2,584 |
| Property and equipment, net (excludes assets held for sale) | 481,374 | 618,229 | 943,175 | 1,267,249 | 1,756,477 |
| Oil and gas properties held for sale, net of accumulated depreciation, depletion, and amortization | 15,208 | 9,896 | 582 | 360 | — |
| Total assets | 516,104 | 664,349 | 1,002,490 | 1,545,935 | 2,006,089 |
| Long term debt | | | | | |
| Credit facility | 55,400 | 6,600 | 158,000 | — | 33,000 |
| Senior Notes, net of unamortized premium | — | — | — | 508,847 | 807,619 |
| Total stockholders' equity | $ 356,380 | $ 527,982 | $ 578,518 | $ 656,028 | $ 740,071 |
| Selected Cash Flow Data: | | | | | |
| Net cash provided by (used in) operating activities | $ (1,586) | $ 60,627 | $ 157,636 | $ 307,015 | $ 327,720 |
| Net cash used in investing activities | (864) | (161,926) | (305,277) | (465,223) | (824,994) |
| Net cash provided by financing activities | $ — | $ 103,389 | $ 149,819 | $ 334,522 | $ 319,276 |
| Sales Volumes: | | | | | |
| Oil (MBbls) | 14.4 | 887.4 | 2,191.0 | 3,887.2 | 5,618.7 |
| Natural gas (MMcf) | 43.0 | 2,773.1 | 5,473.2 | 9,975.9 | 15,395.8 |
| Natural gas liquids (MBbls) | 3.3 | 183.8 | 284.7 | 352.8 | 396.2 |
| Estimated Proved Reserves: | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Oil (MMBbls) | 18.6 | 24.6 | 30.2 | 43.6 | 54.7 |
| Natural gas (Bcf) | 62.9 | 93.0 | 118.5 | 139.6 | 188.6 |
| Natural gas liquids (MMBbls) | 3.8 | 3.6 | 3.1 | 2.9 | 3.4 |
| Total proved reserves (MMBoe) | 32.9 | 43.7 | 53.0 | 69.8 | 89.5 |
| Average Sales Price (before derivatives): | | | | | |
| Oil (MBbls) | $ 83.30 | $ 89.67 | $ 89.08 | $ 91.84 | $ 81.95 |
| Natural gas (MMcf) | $ 4.80 | $ 4.85 | $ 3.62 | $ 4.66 | $ 5.11 |
| Natural gas liquids (MBbls) | $ 63.42 | $ 67.23 | $ 55.54 | $ 51.74 | $ 49.14 |
| Average Sales Price (after derivatives): | | | | | |
| Oil (MBbls) | $ 78.92 | $ 85.51 | $ 88.40 | $ 88.82 | $ 84.00 |
| Natural gas (MMcf) | $ 5.18 | $ 5.09 | $ 3.76 | $ 4.70 | $ 5.16 |
| Natural gas liquids (MBbls) | $ 63.42 | $ 67.23 | $ 55.54 | $ 51.74 | $ 49.14 |
| Expense per BOE: | | | | | |
| Lease operating | $ 16.86 | $ 11.90 | $ 9.06 | $ 8.09 | $ 8.44 |
| Severance and ad valorem taxes | $ 2.67 | $ 3.86 | $ 4.04 | $ 4.61 | $ 5.88 |
| Depreciation, depletion, and amortization | $ 17.52 | $ 18.27 | $ 19.54 | $ 23.75 | $ 26.66 |
| General and administrative | $ 13.01 | $ 11.49 | $ 9.27 | $ 9.40 | $ 9.51 |

(1) Amounts reflect results for continuing operations and exclude results for discontinued operations related to non core properties in California sold or held for sale as of December 31, 2014, 2013 and 2012.

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## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

### Executive Summary

We are a Denver based exploration and production company focused on the extraction of oil and associated liquids rich natural gas in the United States. Our predecessors were founded in 1999 and we went public in December 2011. Our shares of common stock are listed for trading on the NYSE under the symbol "BCEI."

Our oil and liquids weighted assets are concentrated primarily in the Wattenberg Field in Colorado, which we have designated the Rocky Mountain region, and the Dorcheat Macedonia Field in southern Arkansas, which we have designated the Mid Continent region. In addition, we own and operate oil producing assets in the McKamie Patton Field in southern Arkansas and the North Park Basin in Colorado. The Wattenberg Field is one of the premier oil and gas resource plays in the United States benefiting from a low cost structure and strong production efficiencies. Our management team has extensive experience acquiring and operating oil and gas properties and significant expertise in horizontal drilling and fracture stimulation, which we believe will continue to contribute to the development of our sizable inventory of projects, including those targeting the Niobrara and Codell formations in the Rocky Mountain region and oily Cotton Valley sands in the Mid-Continent region. We operate approximately 98% of our proved reserves with an average working interest of approximately 86% providing us with significant control over the rate of development of our asset base. Despite the uncertainty surrounding the global economy and volatility in commodity prices, we believe the economic returns and economic growth generated by our portfolio of oil and gas assets positions us well moving forward.

During 2012, we began the divestiture process of our non core properties in California with the last property sold during the first quarter of 2014. The California properties were treated as assets held for sale, and production, revenue and expenses associated with these properties were removed from continuing operations and reported as discontinued operations. Those results are included in the following discussions unless otherwise noted.

### Financial and Operating Highlights

Our 2014 financial results included:

- Net income of $20.3 million (including $17.0 million from continuing operations), as compared with $69.2 million (including $69.6 million from continuing operations) for 2013;
- Total liquidity of $545.6 million at December 31, 2014, consisting of year end cash balance plus funds available under our revolving credit facility, as compared with $595.0 million at December 31, 2013. Please refer to Liquidity and Capital Resources below for additional discussion;
- Cash flows provided by operating activities of $327.7 million, as compared with $307.0 million in 2013. Please refer to Liquidity and Capital Resources below for additional discussion;
- Impairments of $167.6 million due primarily to depressed commodity prices; and
- Capital expenditures of $650.8 million (excluding acquisitions) as compared with $447.1 million in 2013;

We delivered significant growth in 2014. Operational highlights for 2014 included:

- Increased sales volumes by 45% to 8,580.9 MBoe in 2014 from 5,902.7 MBoe in 2013, with oil and NGL n representing 70% of total sales volumes. Sales volumes exclude discontinued operations. Please refer to the caption Results of Operations below for additional discussion;
- Increased proved reserves to 89.5 MMBoe as of December 31, 2014, an increase of 28% from December 31, 2013;

- Drilled 126 and completed 121 productive wells within the Rocky Mountain region and drilled 48 and completed 50 productive wells within the Mid-Continent region during 2014;
- Acquired approximately 34,000 net acres, leasehold mineral interests and related assets within the Wattenberg Field for approximately $223.7 million which increases our acreage position within the Rocky Mountain region and allows us to leverage current infrastructure and operational expertise;
- Realized positive drilling results on Wattenberg Field catalyst wells which included the delineation of the Niobrara C bench and Codell formation, 40 acre downspacing in the Niobrara B bench and additional extended reach lateral wells in the Niobrara B bench and Niobrara C bench; and
- Increased the Company's borrowing base under its revolving credit facility by $150 million to $600 million during 2014. Please refer to Liquidity and Capital Resources below for additional discussion.

Senior Management Change

On November 10, 2014, the Board of Directors appointed Richard J. Carty, 45, as the Company's President and Chief Executive Officer, effective as of November 11, 2014. Mr. Carty succeeded Marvin M. Chronister, the Company's former Interim President and Chief Executive Officer, who continues with the Company as a member of the Board of Directors. Marvin M. Chronister succeeded the Company's previous President and Chief Executive Officer, Michael R. Starzer, who retired from his position effective January 31, 2014.

Mr. Carty has been Chairman of the Board since the Company's formation in 2010 and was President of West Face Capital (USA) Corp, an affiliate of West Face Capital, from 2009 until 2013. Prior to that period, Mr. Carty was Managing Director of Morgan Stanley Principal Strategies. Prior to Mr. Carty's 14 years at Morgan Stanley, he was a Partner at Gordon Capital Corp, a Toronto-based investment and merchant bank, where he worked for 5 years. Mr. Carty graduated from the University of Waterloo with a bachelor of arts degree in economics.

Outlook for 2015

Because the global economic outlook, central bank policies and commodity price environment are uncertain, we have planned a flexible capital spending program. We estimate our total capital expenditures for 2015 to be approximately $420 million, allocating approximately 90% to the Wattenberg Field and 10% to southern Arkansas. Actual capital expenditures are subject to a number of factors, including economic conditions and commodity prices, and the Company may reduce or augment the capital budget as appropriate throughout the year. This estimated capital investment is expected to result in sales volumes of 27,800 Boe/d to 30,700 Boe/d, while maintaining a strong oil and liquids profile.

Effective as of January 1, 2015, we revised the agreements with our natural gas processors in the Rocky Mountain region to report operated sales volumes on a three stream basis, which allows for separate reporting of NGLs extracted from the natural gas stream and sold as a separate product. The NGL volumes identified by our gas processors are converted to an oil equivalent, based on 42 gallons per Bbl and compared to overall gas equivalent production based on a 1 Bbl to 6 Mcf ratio. We believe that this conversion will more accurately convey our production and sales volumes, will allow our results to be more comparable with those of our peers and will conform more closely to general industry convention.

Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto contained in Part II, Item 8 of this Annual Report on Form 10 K. Comparative results of operations for the period indicated are discussed below.

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The table below presents revenues, sales volumes, and average sales prices for the years ended December 31, 2014 and 2013:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 (3) | 2013 (3) | Change | Percent Change |
| | (in thousands, except percentages) | | | |
| Revenues: | | | | |
| Crude oil sales | $ 460,442 | $ 357,001 | $ 103,441 | 29 % |
| Natural gas sales | 78,714 | 46,490 | 32,224 | 69 % |
| Natural gas liquids sales | 19,470 | 18,256 | 1,214 | 7 % |
| $CO_2$ sales | 7 | 113 | (106) | (94) % |
| Product revenues | $ 558,633 | $ 421,860 | $ 136,773 | 32 % |
| Sales volumes: | | | | |
| Crude oil (MBbls) | 5,618.7 | 3,887.2 | 1,731.5 | 45 % |
| Natural gas (MMcf) | 15,395.8 | 9,975.9 | 5,419.9 | 54 % |
| Natural gas liquids (MBbls) | 396.2 | 352.8 | 43.4 | 12 % |
| Crude oil equivalent (MBoe)(1) | 8,580.9 | 5,902.7 | 2,678.2 | 45 % |
| Average Sales Prices (before derivatives)(2): | | | | |
| Crude oil (per Bbl) | $ 81.95 | $ 91.84 | $ (9.89) | (11) % |
| Natural gas (per Mcf) | $ 5.11 | $ 4.66 | $ 0.45 | 10 % |
| Natural gas liquids (per Bbl) | $ 49.14 | $ 51.74 | $ (2.60) | (5) % |
| Crude oil equivalent (per Boe)(1) | $ 65.10 | $ 71.45 | $ (6.35) | (9) % |
| Average Sales Prices (after derivatives)(2): | | | | |
| Crude oil (per Bbl) | $ 84.00 | $ 88.82 | $ (4.82) | (5) % |
| Natural gas (per Mcf) | $ 5.16 | $ 4.70 | $ 0.46 | 10 % |
| Natural gas liquids (per Bbl) | $ 49.14 | $ 51.74 | $ (2.60) | (5) % |
| Crude oil equivalent (per Boe)(1) | $ 66.53 | $ 69.53 | $ (3.00) | (4) % |

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes $CO_2$ sales.
(2) The derivatives economically hedge the price we receive for crude oil and natural gas.
(3) Amounts reflect results for continuing operations and exclude results for discontinued operations related to non core properties in California sold or held for sale as of December 31, 2014 and 2013.

Revenues increased by 32%, to $558.6 million for the year ended December 31, 2014 compared to $421.9 million for the year ended December 31, 2013 due primarily to an increase in oil, natural gas, and natural gas liquids sales volumes of 45%, 54% and 12%, respectively. The increased volumes were offset by a 9% decrease in crude oil equivalent pricing. The increased volumes are a direct result of the $650.8 million spent for drilling and completion during 2014. For the period from January 1, 2014 through December 31, 2014, we participated in drilling 126 gross (99.4 net) wells in the Rocky Mountain region and 48 gross (42.7 net) wells in the Mid-Continent region, and participated in completing 121 gross (99.7 net) wells in the Rocky Mountain region and 50 gross (44.6 net) wells in the Mid-Continent region. Our Wattenberg Field natural gas is sold without processing into dry gas and NGLs, and therefore, sells at a premium due to its high BTU content.

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The following table summarizes our operating expenses for the years ended December 31, 2014 and 2013:

| | For the Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 (1) | 2013 (1) | Change | Percent Change | |
| | (in thousands, except percentages) | | | | |
| Expenses: | | | | | |
| Lease operating | $ 72,411 | $ 47,771 | $ 24,640 | 52 | % |
| Severance and ad valorem taxes | 50,430 | 27,203 | 23,227 | 85 | % |
| Exploration | 5,346 | 4,213 | 1,133 | 27 | % |
| Depreciation, depletion and amortization | 228,789 | 140,176 | 88,613 | 63 | % |
| Impairment of oil and gas properties | 167,592 | — | 167,592 | 100 | % |
| General and administrative | 81,571 | 55,502 | 26,069 | 47 | % |
| Operating expenses | $ 606,139 | $ 274,865 | $ 331,274 | 116 | % |
| Expenses per Boe: | | | | | |
| Lease operating | $ 8.44 | $ 8.09 | $ 0.35 | 4 | % |
| Severance and ad valorem taxes | 5.88 | 4.61 | 1.27 | 28 | % |
| Exploration | 0.62 | 0.71 | (0.09) | (13) | % |
| Depreciation, depletion and amortization | 26.66 | 23.75 | 2.91 | 12 | % |
| Impairment of oil and gas properties | 19.53 | — | 19.53 | 100 | % |
| General and administrative | 9.51 | 9.40 | 0.11 | 1 | % |
| Operating expenses | $ 70.64 | $ 46.56 | $ 24.08 | 52 | % |

(1) Amounts reflect results for continuing operations and exclude results for discontinued operations related to non core properties in California sold or held for sale as of December 31, 2014 and 2013.

Lease operating expense. Our lease operating expenses increased $24.6 million, or 52%, to $72.4 million for the year ended December 31, 2014 from $47.8 million for the year ended December 31, 2013 and increased on an equivalent basis from $8.09 per Boe to $8.44 per Boe. The increase in lease operating expense was related to the increased sales volumes of 45% attributable to our drilling program. During the year ended December 31, 2014, three of the largest components of lease operating expenses: well servicing, compression and pumping increased $10.0 million, $7.1 million and $3.5 million, respectively, over the comparable period in 2013. We are impacted by high gas gathering pipeline pressures and emission compliance standards which resulted in sales volumes that were less than anticipated. The increase in lease operating expenses on an equivalent basis was due to extreme cold weather experienced during both the first and fourth quarters of 2014 driving up operating costs at a faster pace than sales volumes.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $23.2 million, or 85%, to $50.4 million for the year ended December 31, 2014 from $27.2 million for the year ended December 31, 2013. The increase was primarily related to a 45% increase in sales volumes for the year ended December 31, 2014 over the comparable period in 2013. Colorado has higher severance and ad valorem tax rates than Arkansas and contributed a greater percentage of production for the year ended December 31, 2014 when compared to the same period in 2013. Increased sales volumes from our Wattenberg wells completed in 2014 resulted in a lag in the amount of ad valorem tax credits eligible for deduction against severance taxes generated in the current year because ad valorem taxes are not eligible for deduction during the year a well is completed.

Exploration. Our exploration expense increased $1.1 million to $5.3 million in the year ended December 31, 2014 from $4.2 million in the year ended December 31, 2013. During 2014, we incurred $3.4 million of seismic charges for an acquisition project within the Wattenberg Field, a $1.0 million dry hole charge related to a vertical well within the

Wattenberg Field drilled to test the Lyons formation, and $900,000 in delay rentals. During 2013, we spent $1.5 million on a seismic acquisition project within the Wattenberg Field, wrote off one exploratory dry hole totaling $630,000 and wrote-off $1.7 million on an expired non core lease in the North Park Basin.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $88.6 million, or 63%, to $228.8 million for the year ended December 31, 2014 from $140.2 million for the year ended

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December 31, 2013. Our depreciation, depletion, and amortization expense per Boe increased $2.91, to $26.66 for the year ended December 31, 2014 as compared to $23.75 for the year ended December 31, 2013. The increase was primarily the result of a sales volumes growth of 45% outpacing the corresponding growth in proved reserves of 28%.

Impairment of oil and gas properties. Our impairment of oil and gas properties was $167.6 million for the year ended December 31, 2014. We impaired $127.3 million of proved properties within the Dorcheat Macedonia Field, due to low commodity prices, $25.0 million of non-core proved properties within the McKamie Patton Field, due to low commodity prices, and $15.3 million of proved properties in our McCallum Field due to low commodity prices and a strategic shift to horizontal drilling. The Company incurred no impairment charges for the year ended December 31, 2013. Please refer to Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion.

General and administrative. Our general and administrative expense increased $26.1 million, or 47%, to $81.6 million for the year ended December 31, 2014 from $55.5 million for the year ended December 31, 2013 and increased on an equivalent basis from $9.40 per Boe to $9.51 per Boe. During the year ended December 31, 2014, wages and benefits (excluding executive departures) were $13.8 million higher than the comparable period in 2013. The increase in wages and benefits is primarily due to an increase in headcount as a result of our drilling program between the two years. Cash severance and stock-based compensation for executive departures was $14.1 million for the year ended December 31, 2014.

Derivative gain (loss). Our derivative gain increased $134.1 million to $121.6 million for the year ended December 31, 2014 from a loss of $12.5 million for the comparable period in 2013. The gain incurred was primarily the result of realized prices being less than the contract prices as commodity strip prices, particularly oil, have decreased during 2014. Please refer to Note 13—Derivatives in Part II, Item 8 of this Annual Report on Form 10 K for additional discussion.

Interest expense. Our interest expense increased $24.4 million, or 111%, to $46.4 million for the year ended December 31, 2014 from $22.0 million for the year ended December 31, 2013. The increase for the year ended December 31, 2014 is primarily due to the $200 million 6.75% Senior Notes add-on that occurred during the fourth quarter of 2013 and the issuance of the $300 million 5.75% Senior Notes at the beginning of the third quarter of 2014. Interest expense, including amortization of the premium and financing costs, on the Senior Notes for the year ended December 31, 2014 and 2013 was $42.3 million and $17.0 million, respectively. Interest expense on our revolving credit facility was $3.0 million and amortization of deferred financing costs was $1.1 million for the year ended December 31, 2014. Average debt outstanding during 2014 was $644.4 million as compared to $306.0 million for the comparable period in 2013.

Income tax expense. Our estimate for federal and state income taxes for the year ended December 31, 2014 was $11.0 million from continuing operations as compared to $42.9 million for the year ended December 31, 2013. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. Our effective tax rate for the year ended December 31, 2014 was 39.3% as compared to 38.2% for the year ended December 31, 2013. These rates differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes.

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The table below presents revenues, sales volumes, and average sales prices for the years ended December 31, 2013 and 2012:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2013 (3) | 2012 (3) | Change | Percent Change |
| | (In thousands, except percentages) | | | |
| Revenues: | | | | |
| Crude oil sales | $ 357,001 | $ 195,175 | $ 161,826 | 83 % |
| Natural gas sales | 46,490 | 19,795 | 26,695 | 135 % |
| Natural gas liquids sales | 18,256 | 15,811 | 2,445 | 15 % |
| $CO_2$ sales | 113 | 424 | (311) | (73) % |
| Product revenues | $ 421,860 | $ 231,205 | $ 190,655 | 82 % |
| Sales volumes: | | | | |
| Crude oil (MBbls) | 3,887.2 | 2,191.0 | 1,696 | 77 % |
| Natural gas (MMcf) | 9,975.9 | 5,473.2 | 4,502.7 | 82 % |
| Natural gas liquids (MBbls) | 352.8 | 284.7 | 68.1 | 24 % |
| Crude oil equivalent (MBoe)(1) | 5,902.7 | 3,387.9 | 2,514.8 | 74 % |
| Average Sales Prices (before derivatives)(2): | | | | |
| Crude oil (per Bbl) | $ 91.84 | $ 89.08 | $ 2.76 | 3 % |
| Natural gas (per Mcf) | $ 4.66 | $ 3.62 | $ 1.04 | 29 % |
| Natural gas liquids (per Bbl) | $ 51.74 | $ 55.54 | $ (3.80) | (7) % |
| Crude oil equivalent (per Boe)(1) | $ 71.45 | $ 68.12 | $ 3.33 | 5 % |
| Average Sales Prices (after derivatives)(2): | | | | |
| Crude oil (per Bbl) | $ 88.82 | $ 88.40 | $ 0.42 | — % |
| Natural gas (per Mcf) | $ 4.70 | $ 3.76 | $ 0.94 | 25 % |
| Natural gas liquids (per Bbl) | $ 51.74 | $ 55.54 | $ (3.80) | (7) % |
| Crude oil equivalent (per Boe)(1) | $ 69.53 | $ 67.91 | $ 1.62 | 2 % |

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes $CO_2$ sales.
(2) The derivatives economically hedge the price we receive for crude oil and natural gas.
(3) Amounts reflect results for continuing operations and exclude results for discontinued operations related to non core properties in California sold or held for sale as of December 31, 2013 and 2012.

Revenues increased by 82%, to $421.9 million for the year ended December 31, 2013 compared to $231.2 million for the year ended December 31, 2012 due primarily to increased production, but higher crude oil equivalent prices also contributed. Oil, natural gas, and natural gas liquids sales volumes increased 77%, 82%, and 24%, respectively, during the year ended December 31, 2013, when compared to the year ended December 31, 2012. During the period from January 1, 2013 through December 31, 2013, we drilled and completed 73 gross (67.2 net) wells in the Rocky Mountain region and 45 gross (36.5 net) wells in the Mid-Continent region. The increased volumes are a direct result of the $447.1 million expended for drilling and completion during the year ended December 31, 2013. Our Wattenberg Field natural gas is sold without processing into dry gas and NGLs, and therefore, sells at a premium due to its high BTU content.

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The table below presents operating expenses and per Boe data for the years ended December 31, 2013 and 2012:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2013 (1) | 2012 (1) | Change | Percent Change |
| | (in thousands, except percentages) | | | |
| Expenses: | | | | |
| Lease operating | $ 47,771 | $ 30,695 | $ 17,076 | 56 % |
| Severance and ad valorem taxes | 27,203 | 13,674 | 13,529 | 99 % |
| Exploration | 4,213 | 10,715 | (6,502) | (61) % |
| Depreciation, depletion and amortization | 140,176 | 66,202 | 73,974 | 112 % |
| Impairment of oil and gas properties | — | 611 | (611) | (100) % |
| General and administrative | 55,502 | 31,405 | 24,097 | 77 % |
| Operating expenses | $ 274,865 | $ 153,302 | $ 121,563 | 79 % |
| Expenses per Boe: | | | | |
| Lease operating | $ 8.09 | $ 9.06 | $ (0.97) | (11) % |
| Severance and ad valorem taxes | 4.61 | 4.04 | 0.57 | 14 % |
| Exploration | 0.71 | 3.16 | (2.45) | (78) % |
| Depreciation, depletion and amortization | 23.75 | 19.54 | 4.21 | 22 % |
| Impairment of oil and gas properties | — | 0.18 | (0.18) | (100) % |
| General and administrative | 9.40 | 9.27 | 0.13 | 1 % |
| Operating expenses | $ 46.56 | $ 45.25 | $ 1.31 | 3 % |

(1) Amounts reflect results for continuing operations and exclude results for discontinued operations related to non core properties in California sold or held for sale as of December 31, 2013 and 2012.

Lease operating expense. Our lease operating expenses increased $17.1 million, or 56%, to $47.8 million for the year ended December 31, 2013 from $30.7 million for the year ended December 31, 2012 and decreased on an equivalent basis from $9.06 per Boe to $8.09 per Boe. The increase in lease operating expense was related to the increased sales volumes attributable to our drilling program and the operation of an additional gas plant that was constructed during 2012 but did not come on line until February of 2013. During the year ended December 31, 2013, three of the largest components of lease operating expenses: well servicing, compression, and pumping increased $6.8 million, $2.6 million, and $2.3 million, respectively, over the comparable period in 2012. Gas plant operating expense, which is a component of lease operating expense, increased $3.8 million, or 45%, to $12.2 million for the year ended December 31, 2013 from $8.4 million for the year ended December 31, 2012. Our lease operating expense per Boe decreased due to higher sales volumes from our horizontal wells in the Wattenberg Field outpacing operating costs during 2013. Our gas plant that was constructed in 2012 did not come on line until February 2013 causing our lease operating expense per Boe to be higher than it would be if the gas plant were operating at full capacity.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $13.5 million, or 99%, to $27.2 million for the year ended December 31, 2013 from $13.7 million for the year ended December 31, 2012. The increase was primarily related to a 74% increase in sales volumes with a corresponding 5% increase in crude oil equivalent prices for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Exploration. Our exploration expense decreased $6.5 million, or 61%, to $4.2 million in the year ended December 31, 2013 from $10.7 million in the year ended December 31, 2012. During 2013, we spent $1.5 million on a seismic acquisition project within the Wattenberg Field and wrote off one exploratory dry hole totaling $630,000 and wrote-off

$1.7 million on an expired non core lease in the North Park Basin. During 2012, we wrote-off three exploratory dry holes in the North Park Basin amounting to $8.4 million and we spent $2.0 million on a seismic acquisition project in the North Park Basin.

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Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $74.0 million, or 112%, to $140.2 million for the year ended December 31, 2013 from $66.2 million for the year ended December 31, 2012. Our depreciation, depletion, and amortization expense per Boe increased $4.21, to $23.75 for the year ended December 31, 2013 as compared to $19.54 for the year ended December 31, 2012. The increase in depreciation, depletion, and amortization expense is primarily due to a 55% increase in depreciable assets at December 31, 2013 when compared to the same period in 2012. The increase per Boe is related to a larger increase in production of 74% versus the corresponding increase in proved developed reserves of 35%.

General and administrative. Our general and administrative expense increased $24.1 million, or 77%, to $55.5 million for the year ended December 31, 2013 from $31.4 million for the year ended December 31, 2012 and increased on an equivalent basis from $9.27 per Boe to $9.40 per Boe. During the year ended December 31, 2013, wages and benefits, stock-based compensation, and professional service expenses were $13.2 million, $8.2 million, and $2.7 million higher, respectively, than the year ended December 31, 2012. The increase in wages and stock-based compensation is primarily due to increased headcount and incentive compensation, which is tied directly to improved Company results. The majority of the increase in professional services relates to outsourced land work performed during the year relating to our expanded drilling program.

Derivative gain (loss). Our derivative loss increased $13.4 million, or 1,449%, to $12.5 million for the year ended December 31, 2013 from a $924,000 gain for the comparable period in 2012. The loss incurred on derivative contracts during 2013 was primarily the result of realized prices being greater than the contract prices.

Interest expense. Our interest expense increased $17.9 million, or 437%, to $22.0 million for the year ended December 31, 2013 from $4.1 million for the year ended December 31, 2012. The increase for the year ended December 31, 2013 compared to the year ended December 31, 2012 is primarily related to the issuance of $500 million in 6.75% Senior Notes during 2013. Interest expense on the 6.75% Senior Notes in 2013 was $17.0 million, of which $798,000 related to the amortization of debt issuance costs related to the 6.75% Senior Notes offering, offset by the amortization of the premium on the 6.75% Senior Notes of $153,000. Interest expense on our revolving credit facility was $4.1 million and amortization of deferred financing costs was $900,000 for the year ended December 31, 2013. The average outstanding long-term debt balance during the year ended December 31, 2013 was $306.0 million as compared to $74.7 million for the year ended December 31, 2012.

Income tax expense. Our estimate for federal and state income taxes for the year ended December 31, 2013 was $42.9 million from continuing operations as compared to $30.0 million for the year ended December 31, 2012. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. Our effective tax rate for the year ended December 31, 2013 was 38.2% as compared to 40.2% for the year ended December 31, 2012, these rates differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes.

Results for Discontinued Operations

During June of 2012, the Company began marketing, with an intent to sell, all of its oil and gas properties in California. Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. The Company determined that our intent to sell out of an entire region qualified for discontinued operations accounting and these assets have been presented as discontinued operations in the accompanying consolidated statements of operations and comprehensive income (“accompanying statements of operations”).

The majority of these properties were sold in 2012. The remaining property located in the Midway Sunset Field sold on March 21, 2014 for approximately $6.0 million and resulted in a $5.5 million gain.

The operating results before income taxes for our California properties for the year ended December 31, 2014 were net revenues of $361,000, and operating expenses of $446,000, as compared to net revenues of $1.7 million, and operating expenses of $2.3 million for the year ended December 31, 2013. Sales volumes for the years ended December 31, 2014 and 2013 were 10 Boe/d and 47 Boe/d, respectively. The operating results before income taxes for our California properties for the year ended December 31, 2012 were net revenues of $5.4 million, and operating expenses of $6.3 million, of which, $1.6 million is due to impairments of proved properties. Sales volumes for the year ended December 31, 2012 were 147 Boe/d.

Please refer to Note 3—Discontinued Operations in Part II, Item 8 of this Annual Report on Form 10 K for additional discussion.

Liquidity and Capital Resources

We fund our operations, capital expenditures and working capital requirements with cash flows from our operating activities and borrowings under our revolving credit facility. Periodically, we access debt and capital markets and sell non core properties to provide additional liquidity.

We believe that our cash on hand of $2.6 million, availability under our revolving credit facility of $543.0 million, if we elect to access the entire borrowing base, net proceeds of $202.6 million from our common stock offering completed on February 6, 2015 and cash flow from operating activities will be sufficient to fund our planned capital expenditures of approximately $420 million and operating expenses and comply with our debt covenants for at least the next 12 months. To the extent actual operating results differ from our anticipated results or our borrowing base under our revolving credit facility is redetermined at a substantially lower amount, our liquidity could be adversely affected.

On April 9, 2013, we sold $300 million of 6.75% Senior Notes that mature on April 15, 2021. Interest on the 6.75% Senior Notes began accruing on April 9, 2013, and we will pay interest on April 15 and October 15 of each year, which began on October 15, 2013. On November 15, 2013, we sold an additional $200 million aggregate principal amount of 6.75% Senior Notes, above par, as an additional issuance of our existing 6.75% Senior Notes that mature on April 15, 2021. The net proceeds from the sales of the 6.75% Senior Notes were approximately $496.8 million after the premium and deduction of $12.2 million of expenses and underwriting discounts and commissions. The proceeds were used to repay all of the then outstanding balance under our revolving credit facility and for general corporate purposes, which included funding the Company's drilling and development program and other capital expenditures.

On May 15, 2014, our borrowing base under the revolving credit facility was increased to $525 million from $450 million. We elected to limit bank commitments to $400 million while reserving the option to access, at the Company's request, the full $525 million. Upon issuance of our 5.75% Senior Notes on July 15, 2014, our borrowing base was adjusted down to $450 million. On September 30, 2014, our revolving credit facility was amended to increase our borrowing base to $600 million and we elected to limit our bank commitment to $500 million while reserving the option to access the full $600 million, at the Company's request. As of December 31, 2014, we had $33 million outstanding on our revolving credit facility and a $24 million letter of credit issued resulting in $543 million available borrowing capacity, if we elect to take advantage of the entire borrowing base (without giving effect to any scheduled or interim redetermination). Our next scheduled borrowing base redetermination is in May 2015. Our weighted-average interest rate (excluding amortization of deferred financing costs and the accretion of our contractual obligation for land acquisition) on borrowings from our revolving credit facility was 2.31% and 2.40%, respectively, for the years ended December 31, 2014 and 2013. Our commitment fees were $2.0 million and $1.8 million, respectively, for the years ended December 31, 2014 and 2013. Please refer to the Credit Facility section below for additional discussion.

On July 8, 2014, we acquired approximately 34,000 net acres, leasehold mineral interests and related assets in the Wattenberg Field for approximately $223.7 million. We paid $174.6 million in cash and issued 853,492 shares of the Company's common stock valued at $57.47 per share, the market price at the date of closing, for the acquired assets. The acquisition had an effective date of June 1, 2014 and allowed us to leverage our current infrastructure and technical expertise within the Wattenberg Field. Please refer to Note 2 – Acquisitions in Part II, Item 8 of this Annual Report on Form 10 K for additional discussion.

On July 15, 2014, we issued $300 million of 5.75% Senior Notes that mature on February 1, 2023. Interest on the 5.75% Senior Notes began accruing on July 15, 2014, and we will pay interest on February 1 and August 1 of each year, beginning on February 1, 2015. The net proceeds from the sale of the 5.75% Senior Notes were approximately $293.4 million after deductions of $6.6 million of expenses and underwriting discounts and commissions. The net

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proceeds were used to pay off the Company's outstanding revolving credit facility balance and for general corporate purposes, which included funding our drilling and development program and other capital expenditures. Please refer to Note 7 – Long-Term Debt in Part II, Item 8 of this Annual Report on Form 10 K for additional discussion.

On February 6, 2015, the Company completed a public offering of 8,050,000 shares of its common stock generating net proceeds of $202.6 million after deducting underwriter discounts, commissions and estimated offering expenses of approximately $6.7 million. The Company intends to use the net proceeds to repay all of the outstanding borrowings under its revolving credit facility and for general corporate purposes, including its drilling and development program and other capital expenditures.

In 2015, we have 6,251 Bbls/d of oil hedged with three-way collars with an average ceiling of $95.52/Bbl, average floor of $84.43/Bbl and average short floor of $68.20/Bbl. In 2015, we have 15,000 Mcf/d of natural gas hedged with three-way collars with an average ceiling of $4.75/Mcf, average floor of $4.00/Mcf and average short floor of $3.50/Mcf. These commodity derivatives represent approximately 60% of our anticipated production in 2015. In 2016, we have 5,500 Bbls/d of oil hedged with three-way collars with an average ceiling of $96.83/Bbl, average floor of $85.00/Bbl and average short floor of $70.00/Bbl. Currently, forward oil prices are below the average price of our short-puts associated with our three-way collars. Should monthly crude oil settlement prices occur below the strike price of our short-puts associated with the Company's three-way collars, we will receive a payment from our hedging counterparty equal to the difference between the strike prices of the short-put and long-put multiplied by the monthly volume associated with the three-way collar. We expect that in the future our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and natural gas. Please see the Derivative Activity section of Part I, Item 1 of this Annual Report on Form 10-K for a summary of derivatives in place.

The following table summarizes our cash flows and other financial measures for the periods indicated.

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Financial Measures: | | | |
| Net cash provided by operating activities | $ 327,720 | $ 307,015 | $ 157,636 |
| Net cash used in investing activities | (824,994) | (465,223) | (305,277) |
| Net cash provided by financing activities | 319,276 | 334,522 | 149,819 |
| Cash and cash equivalents | 2,584 | 180,582 | 4,268 |
| Acquisition of oil and gas properties | 179,566 | 13,797 | 13,920 |
| Exploration and development of oil and gas properties, natural gas plant capital expenditures, and payments of contractual obligations | 653,486 | 435,037 | 297,115 |

Cash flows provided by operating activities

During 2014, we generated $327.7 million of cash provided by operating activities, an increase of $20.7 million from 2013. The increase in cash flows from operating activities resulted primarily from a 45% increase in sales volumes offset by a 9% decrease in realized crude oil equivalent prices. These positive factors were partially offset by increased lease operating expense, production taxes, cash portion of general and administrative expense, and cash portion of interest expense during 2014 as compared to 2013. See Results of Operations above for more information on the factors driving these changes.

During 2013, we generated $307.0 million of cash provided by operating activities, an increase of $149.4 million from 2012. The increase in cash flows from operating activities resulted primarily from an increase in sales volumes of 74% compounded with a 5% increase in realized crude oil equivalent prices. These positive factors were partially offset by increased lease operating expense, production taxes, cash portion of general and administrative expense, and cash portion of interest expense during 2013 as compared to 2012. See Results of Operations above for more information on the factors driving these changes.

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Cash flows used in investing activities

Expenditures for development of oil and natural gas properties is the primary use of our capital resources. Net cash used in investing activities for the year ended December 31, 2014 increased $359.8 million, inclusive of $6.7 million of proceeds from the sale of our one remaining California property and other non-core properties, compared to the same period in 2013. For the year ended December 31, 2014, cash used for the acquisition of oil and gas properties was $179.6 million, cash used for the development of oil and natural gas properties (including cash used for natural gas plant capital expenditures and contractual land obligation payments) was $653.5 million, and cash used for non oil and gas property additions was $6.3 million. For the year ended December 31, 2013, cash used for the acquisition of oil and gas properties was $13.8 million, cash used for the development of oil and natural gas properties (including cash used for natural gas plant capital expenditures and contractual land obligation payments) was $435.0 million, and cash used for non oil and gas property additions was $5.1 million. For the year ended December 31, 2012, cash used for the acquisition of oil and gas properties was $13.9 million, cash used for the development of oil and natural gas properties (including cash used for natural gas plant capital expenditures) was $297.1 million, cash used for non oil and gas property additions was $3.1 million, and cash received for the sale of non core oil and gas properties in California was $9.3 million.

Cash flows provided by financing activities

Net cash provided by financing activities for the year ended December 31, 2014 decreased $15.2 million compared to the same period in 2013. The decrease is due to a combination of net proceeds from the sale of 5.75% Senior Notes being $204.3 million lower in 2014 than the sale of the 6.75% Senior Notes in 2013 and the increase in net proceeds from the revolving credit facility being $191.0 million higher in 2014 than in 2013. Net cash provided by financing activities for the year ended December 31, 2013 increased $184.7 million compared to the same period in 2012. The issuance of our 6.75% Senior Notes during 2013 provided $497.3 million in net proceeds, which was offset by net payments on our revolving credit facility of $158.0 million as compared to net borrowings on our revolving credit facility of $151.4 million during 2012.

Credit facility

Revolving Credit Facility

The administrative agent of our $1.0 billion revolving credit facility is KeyBank National Association. The revolving credit facility provides for interest rates plus an applicable margin to be determined based on the London Interbank Offered Rate (“LIBOR”) or a bank base rate (“Base Rate”), at the Company’s election. LIBOR borrowings bear interest at LIBOR plus 1.50% to 2.50% depending on the utilization level, and the Base Rate borrowings bear interest at the “Bank Prime Rate,” as defined in the revolving credit facility, plus .50% to 1.50%.

Our approved borrowing base under the revolving credit facility, which was $600 million as of December 31, 2014, is redetermined semiannually by May 15 and November 15 and may be redetermined up to one additional time between such scheduled determinations upon our request or upon the request of the required lenders (defined as lenders holding 66$2/_3$% of the aggregate commitments). The borrowing base is determined by the value of our oil and gas reserves. The borrowing base is redetermined (i) in the sole discretion of the administrative agent and all of the lenders, (ii) in accordance with their customary internal standards and practices for valuing and redetermining the value of oil and gas properties in connection with reserve based oil and natural gas loan transactions, (iii) in conjunction with the most recent engineering report and other information received by the administrative agent and the lenders relating to our proved reserves and (iv) based upon the estimated value of our proved reserves as determined by the administrative agent and the lenders. As of December 31, 2014, the Company elected to limit bank commitments to $500 million while reserving the option to access, at the Company’s request, the full $600 million prior to the next semi annual redetermination.

As of December 31, 2014, we had $33 million outstanding under our revolving credit facility and nil outstanding under our revolving credit facility as of the date of this filing. The revolving credit facility matures on September 15, 2018. Amounts borrowed and repaid under the revolving credit facility may be reborrowed. The revolving credit facility may be used only to finance development of oil and gas properties, for working capital and for other general corporate purposes.

Our obligations under the revolving credit facility are secured by first priority liens on all of our property and assets (whether real, personal, or mixed, tangible or intangible), including our proved reserves and our oil and gas properties (which term is defined to include fee mineral interests, term mineral interests, leases, subleases, farm outs, royalties, overriding royalties, net profit interests, carried interests, production payments, back in interests and reversionary interests). The revolving credit facility is guaranteed by us and all of our direct and indirect subsidiaries.

The applicable margin varies on a daily basis based on the percentage outstanding under the borrowing base. We incur quarterly commitment fees based on the unused amount of the borrowing base ranging from 0.375% and 0.50% per annum. We may prepay loans under the revolving credit facility at any time without premium or penalty (other than customary LIBOR breakage costs).

The revolving credit facility contains various covenants limiting our ability to:

- grant or assume liens;
- incur or assume indebtedness;
- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make certain distributions;
- make certain loans, advances and investments;
- engage in transactions with affiliates;
- enter into sale and leaseback, take or pay or hydrocarbon prepayment transactions; or
- enter into certain swap agreements.

The revolving credit facility also contains covenants requiring us to maintain:

- a current ratio (i.e., the ratio of current assets to current liabilities, excluding unsettled derivatives) of not less than 1.0 to 1.0 (current assets include, as of the date of calculation, the aggregate of all lenders' unused commitment amounts); and
- a debt to earnings before interest, taxes, depreciation and amortization and other items (as defined in the revolving credit facility) ("EBITDAX") coverage ratio of not more than: 4.00 to 1.00 as of the quarter ending December 31, 2011 and for each quarter thereafter (using the trailing four quarter EBITDAX).

As of December 31, 2014 and through the filing date of this report, we were in compliance with all financial and non financial covenants. If an event of default exists under the revolving credit facility, the lenders will be able to accelerate the maturity of the loan and exercise other rights and remedies.

The revolving credit facility contains customary events of default, including:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- the failure of any representation or warranty to be materially true and correct when made;

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- failure to observe any agreement, obligation or covenant in the credit agreement, subject to cure periods for certain failures;
- a cross default for the payment of any other indebtedness of at least $2 million;
- bankruptcy or insolvency;
- judgments against us or our subsidiaries, in excess of $2 million, that are not stayed;
- certain ERISA events involving us or our subsidiaries; and
- a change in control (as defined in the revolving credit facility), including the ownership by a "person" or "group" (as defined under the Securities and Exchange Act of 1934, as amended, but excluding certain permitted stockholders) directly or indirectly, of more than 35% of our common stock, other than certain of our current stockholders.

Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2014:

| | Total | Less than 1 Year | 1 - 3 Years | 3 - 5 Years | More than 5 Years |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| Contractual Obligation | | | | | |
| Senior Notes | $ 800,000 | $ — | $ — | $ — | $ 800,000 |
| Interest on Senior Notes | 351,829 | 51,000 | 102,000 | 102,000 | 96,829 |
| Revolving credit facility(1) | 33,000 | 33,000 | — | — | — |
| Delivery commitments (2) | 540,036 | 36,351 | 156,227 | 179,222 | 168,236 |
| Wattenberg field lease acquisition | 24,000 | 12,000 | 12,000 | — | — |
| Operating leases(2) | 13,377 | 2,091 | 4,566 | 4,823 | 1,897 |
| Asset retirement obligations(3) | 21,626 | 1,760 | 1,272 | 1,826 | 16,768 |
| Total | $ 1,783,868 | $ 136,202 | $ 276,065 | $ 287,871 | $ 1,083,730 |

(1) The Company assumes that the principal balance on the revolving credit facility will be paid in full in the subsequent year. The actual payments made on our revolving credit facility may vary significantly.

(2) See Note 8—Commitments and Contingent Liabilities to our consolidated financial statements for a description of operating leases and purchase and transportation agreements.

(3) Amount represents our estimate of future retirement obligations on a discounted basis unless otherwise noted. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. There is $162,000 included in the less than one year category and is not discounted and is included in accounts payable and accrued expenses as of December 31, 2014. Please see Note 11—Asset Retirement Obligation, for additional discussion.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis

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for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Note 1—Summary of Significant Accounting Policies to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized at cost when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and other associated costs and leasehold costs of proved properties are amortized on a unit of production basis over the remaining life of proved developed reserves and proved reserves, respectively.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit of production amortization rate for an entire field, in which case a gain or loss is recognized currently. Gains or losses from the disposal of properties are recognized currently.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit of production basis over the remaining life of the related proved developed reserves.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing or expiration of unproved lease acquisition costs are recorded as exploration expense in the statements of operations and comprehensive income in our consolidated financial statements. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit of production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and natural gas reserve quantities and Standardized Measure

Our internal corporate reservoir engineering group prepares, and our third party petroleum consultant audits our estimates of oil and natural gas reserves and associated future net revenues. While the SEC has recently adopted rules which allow us to disclose proved, probable and possible reserves, we have elected to disclose only proved reserves in this Annual Report on Form 10 K. The SEC's revised rules define proved reserves as the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Our internal corporate reservoir engineering group and our third party petroleum consultant must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy

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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, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue recognition

Revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. Substantially all of our production is sold to purchasers under short term (less than 12 month) contracts at market based prices. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment.

Subsequently, these revenue deductions are adjusted to reflect actual charges based on third party documents. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and natural gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded.

Impairment of unproved properties

We assess our unproved properties periodically for impairment on a property by property basis based on remaining lease terms, drilling results or future plans to develop acreage and record impairment expense for any decline in value.

We have historically recognized impairment expense for unproved properties at the time when the lease term has expired or sooner if, in management's judgment, the unproved properties have lost some or all of their carrying value. We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;

- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and

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- our evaluation of the continuing successful results from the application of completion technology in the Niobrara formation by us or by other operators in areas adjacent to or near our unproved properties.

The assessment of unproved properties to determine any possible impairment requires significant judgment.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The asset retirement obligation ("ARO") for oil and gas properties represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized cost is depreciated on the unit of production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in our consolidated statements of operations and comprehensive income.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. Derivative instruments are adjusted to fair value every accounting period. Derivative cash settlements and gains and losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under derivative gain (loss) in our consolidated statements of operations and comprehensive income.

Stock based compensation

Restricted Stock Awards. We recognize compensation expense for all restricted stock awards made to employees and directors. Stock based compensation expense is measured at the grant date based on the fair value of the award and is recognized as an expense on a straight line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Assumptions regarding forfeiture rates are subject to change. Any such changes could result in different valuations and thus impact the amount of stock based compensation expense recognized. Stock based compensation expense recorded for restricted stock awards is included in general and administrative expenses on our consolidated statements of operations and comprehensive income.

Performance Stock Units. We recognize compensation expense for all performance stock unit awards made to officers. Stock based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight line basis over the requisite service period, which is generally the vesting period. The fair value of the performance stock unit is measured at the grant date with a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). Stock based compensation expense recorded for performance stock units is included in general and administrative expenses on our consolidated statements of operations and comprehensive income.

Income taxes

Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance would be established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. We did not have a valuation allowance as of December 31, 2014.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. We did not have any uncertain tax positions as of the year ended December 31, 2014.

Recent accounting pronouncements

In April 2014, the FASB issued Update No. 2014-08 - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The update is aimed at reducing the frequency of disposals reported as discontinued operations by focusing on strategic shifts that have or will have a major effect on an entity's operations and financial results. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2014 and is to be applied prospectively. This guidance will be applied by the Company upon future disposal of assets on a prospective basis.

In May 2014, the FASB issued Update No. 2014-09 - Revenue From Contracts With Customers. The update prescribes two acceptable methods and is effective for the annual period beginning after December 15, 2016, including interim periods within that reporting period. The Company is currently evaluating the provisions of this guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In June 2014, the FASB issued Update No. 2014-12 - Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could be Achieved after the Requisite Service Period. The guidance relates to the recognition of share-based compensation when an award provides that a performance target can be achieved after the requisite service period. This authoritative accounting guidance may be applied either prospectively or retrospectively and is effective for annual periods and interim periods beginning after December 15, 2015. The Company is currently evaluating the provisions of this guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In August 2014, the FASB issued Update No. 2014-15 - Presentation of Financial Statements – Going Concern that requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity's ability to continue as a going concern within one year after the date that the entity's financial statements are issued, or within one year after the date that the entity's financial statements are available to be issued, and to provide disclosures when certain criteria are met. This guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In November 2014, the FASB issued Update No. 2014-17 – Business Combinations – Pushdown Accounting that gives an acquired entity an option to apply pushdown accounting in its separate financial statements upon

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occurrence of an event in which an acquirer obtains control of the acquired entity. This guidance was effective on November 18, 2014 for any future change-in-control event. This guidance will be applied by the Company if it were to experience a change-in-control.

Effects of Inflation and Pricing

Inflation in the United States has been relatively low in recent years and dropped even lower during 2014, which did not have a material impact on our results of operations for the periods ended December 31, 2014, 2013 and 2012. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations, depletion expense, impairment assessments of oil and gas properties, ARO, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. Given the recent decline in oil and gas prices, we would anticipate that costs of materials and services would also decline.

Off balance sheet arrangements

Currently, we do not have any off balance sheet arrangements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risks.

Oil and Natural Gas Price Risk

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil and natural gas, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels, local and global politics, and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If oil and natural gas prices declined by 10% per Bbl and Mcf, then our PV 10 as of December 31, 2014 would have been lower by approximately 20% or $273.6 million. A 10% decrease in pricing for our proved undeveloped reserves would result in a reduction of 4,873 MBoe, a 5.4% change.

Commodity Derivative Contracts

Our primary commodity risk management objective is to reduce volatility in our cash flows. We enter into derivative contracts for oil and natural gas using NYMEX futures or over the counter derivative financial instruments with only well capitalized counterparties which have been approved by our board of directors.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in derivative contracts, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices.

Presently, all of our derivative arrangements are concentrated with five counterparties, all of which are lenders under our credit facility. If these counterparties fail to perform their obligations, we may suffer financial loss or be prevented from realizing the benefits of favorable price changes in the physical market.

The result of oil market prices exceeding our swap prices or collar ceilings requires us to make payment for the settlement of our derivatives, if owed by us, generally up to 15 business days before we receive market price cash payments from our customers. This could have a material adverse effect on our cash flows for the period between derivative settlement and payment for revenues earned.

Please refer to the Derivative Activities section of Part I, Item 1 of this Annual Report on Form 10 K for summary derivative activity tables.

For the oil and natural gas derivatives outstanding at December 31, 2014, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2014 would change our derivative gain (loss) by $(17.2) million and $15.3 million, respectively.

Interest Rates

At December 31, 2014, we had $33.0 million outstanding under our revolving credit facility and nil outstanding under our revolving credit facility on the date of this filing.  Borrowings under our revolving credit facility bear interest at a fluctuating rate that is tied to an adjusted Base Rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. As of December 31, 2014 and through the filing date of this report, the Company had minimal interest expense associated with its revolving credit facility, therefore a one percentage point change within the interest rate would have a minimal impact on our financials.

Counterparty and Customer Credit Risk

In connection with our derivatives activity, we have exposure to financial institutions in the form of derivative transactions. Five lenders under our credit facility are currently counterparties on our derivative instruments currently in place and have investment grade credit ratings. We expect that any future derivative transactions we enter into will be with these or other lenders under our credit facility that will carry an investment grade credit rating.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. Please refer to the section titled Principal Customers under Part I, Item 1 of this Annual Report on Form 10 K for further details about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history and financial resources of our customers, but we do not require our customers to post collateral.

Marketability of Our Production

The marketability of our production from the Mid Continent and Rocky Mountain regions depends in part upon the availability, proximity and capacity of third party refineries, access to regional trucking, pipeline and rail infrastructure, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services, pipelines and rail facilities that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Currently, there are no natural gas pipeline systems that service wells in the North Park Basin, which is prospective for the Niobrara shale. In addition, we are not aware of any plans to construct a facility necessary to process natural gas produced from this basin. If neither we nor a third party constructs the required pipeline system and processing facility, we may not be able to fully test or develop our resources in the North Park Basin.

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Item 8. Financial Statements and Supplementary Data

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Bonanza Creek Energy, Inc.

We have audited the accompanying consolidated balance sheets of Bonanza Creek Energy, Inc. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Bonanza Creek Energy, Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Bonanza Creek Energy, Inc.'s and subsidiaries' internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013, and our report dated February 27, 2015 expressed an unqualified opinion on the effectiveness of Bonanza Creek Energy, Inc.'s internal control over financial reporting.

/s/ Hein & Associates LLP

Denver, Colorado

February 27, 2015

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

| | As of December 31, 2014 | 2013 |
|---|---|---|
| | (in thousands, except per share data) | |
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $ 2,584 | $ 180,582 |
| Accounts receivable: | | |
| Oil and gas sales | 54,574 | 57,485 |
| Joint interest and other | 37,202 | 12,915 |
| Prepaid expenses and other | 12,522 | 1,638 |
| Inventory of oilfield equipment | 15,353 | 10,696 |
| Derivative asset | 86,240 | 858 |
| Total current assets | 208,475 | 264,174 |
| Property and equipment (successful efforts method), at cost | | |
| Proved properties | 1,924,380 | 1,257,288 |
| Less: accumulated depreciation, depletion and amortization | (592,073) | (224,848) |
| Total proved properties, net | 1,332,307 | 1,032,440 |
| Unproved properties | 206,721 | 45,081 |
| Wells in progress | 139,208 | 110,848 |
| Natural gas plant, net of accumulated depreciation of $8,457 in 2014 and $5,903 in 2013 | 67,840 | 71,474 |
| Other property and equipment, net of accumulated depreciation of $6,087 in 2014 and $2,822 in 2013 | 10,401 | 7,406 |
| Oil and gas properties held for sale, net of accumulated depreciation, depletion, and amortization of $- in 2014 and $1,463 in 2013 (note 3) | — | 360 |
| Total property and equipment, net | 1,756,477 | 1,267,609 |
| Long-term derivative asset | 17,765 | 293 |
| Other noncurrent assets | 23,372 | 13,859 |
| Total assets | $ 2,006,089 | $ 1,545,935 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current liabilities: | | |
| Accounts payable and accrued expenses (note 6) | $ 145,788 | $ 121,665 |
| Oil and gas revenue distribution payable | 40,659 | 36,241 |
| Contractual obligation for land acquisition | 12,000 | 12,000 |
| Derivative liability | — | 5,320 |
| Total current liabilities | 198,447 | 175,226 |
| Long-term liabilities: | | |
| Long-term debt | 840,619 | 508,847 |
| Contractual obligation for land acquisition | 11,186 | 22,033 |
| Ad valorem taxes | 28,635 | 18,867 |
| Derivative liability | — | 1,203 |
| Deferred income taxes, net | 165,667 | 152,681 |
| Asset retirement obligations | 21,464 | 11,050 |

| | | |
|---|---|---|
| Total liabilities | 1,266,018 | 889,907 |
| Commitments and contingencies (note 8) | | |
| Stockholders' equity: | | |
| Preferred stock, $.001 par value, 25,000,000 shares authorized, none outstanding | — | — |
| Common stock, $.001 par value, 225,000,000 shares authorized, 41,287,270 and 40,285,919 issued and outstanding in 2014 and 2013, respectively | 41 | 40 |
| Additional paid-in capital | 591,511 | 527,752 |
| Retained earnings | 148,519 | 128,236 |
| Total stockholders' equity | 740,071 | 656,028 |
| Total liabilities and stockholders' equity | $ 2,006,089 | $ 1,545,935 |

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands, except share data) | | |
| Operating net revenues: | | | |
| Oil and gas sales | $ 558,633 | $ 421,860 | $ 231,205 |
| Operating expenses: | | | |
| Lease operating expense | 72,411 | 47,771 | 30,695 |
| Severance and ad valorem taxes | 50,430 | 27,203 | 13,674 |
| Exploration | 5,346 | 4,213 | 10,715 |
| Depreciation, depletion and amortization | 228,789 | 140,176 | 66,202 |
| Impairment of oil and gas properties | 167,592 | — | 611 |
| General and administrative (including $20,716, $12,638 and $4,483 respectively, of stock compensation) | 81,571 | 55,502 | 31,405 |
| Total operating expenses | 606,139 | 274,865 | 153,302 |
| Income (loss) from operations | (47,506) | 146,995 | 77,903 |
| Other income (expense): | | | |
| Derivative gain (loss) | 121,615 | (12,472) | 924 |
| Interest expense | (46,447) | (21,972) | (4,133) |
| Other income (loss) | 345 | (43) | (132) |
| Total other income (expense) | 75,513 | (34,487) | (3,341) |
| Income from continuing operations before taxes | 28,007 | 112,508 | 74,562 |
| Current income tax expense | (149) | (248) | (532) |
| Deferred income tax expense | (10,876) | (42,678) | (29,459) |
| Income from continuing operations | 16,982 | 69,582 | 44,571 |
| Discontinued operations (Note 3) | | | |
| Loss from operations associated with oil and gas properties held for sale | (85) | (644) | (927) |
| Gain on sale of oil and gas properties | 5,496 | — | 4,192 |
| Income tax (expense) benefit | (2,110) | 246 | (1,313) |
| Income (loss) from discontinued operations | 3,301 | (398) | 1,952 |
| Net income | $ 20,283 | $ 69,184 | $ 46,523 |
| Comprehensive income | $ 20,283 | $ 69,184 | $ 46,523 |
| Basic net income (loss) per share: (1) | | | |
| Income from continuing operations | $ 0.42 | $ 1.73 | $ 1.12 |
| Income (loss) from discontinued operations | $ 0.08 | $ (0.01) | $ 0.05 |
| Net income per common share | $ 0.50 | $ 1.72 | $ 1.17 |
| Basic weighted-average common shares outstanding | 40,139 | 39,337 | 39,052 |
| Diluted income (loss) per share: (1) | | | |
| Income from continuing operations | $ 0.41 | $ 1.72 | $ 1.12 |
| Income (loss) from discontinued operations | $ 0.08 | $ (0.01) | $ 0.05 |
| Net income per common share | $ 0.49 | $ 1.71 | $ 1.17 |
| Diluted weighted-average common shares outstanding | 40,290 | 39,403 | 39,052 |

(1) The Company follows the two class method when computing the basic and diluted income (loss) per share, which allocates earnings between common shareholders and participating securities. Please refer to Note 14—Earnings per

Share, for a detailed calculation.

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

| | Common Stock Shares | Amount | Additional Paid-In Capital | Retained Earnings | Total |
|---|---|---|---|---|---|
| | (in thousands, except share data) | | | | |
| Balances, January 1, 2012 | 39,477,584 | $ 40 | $ 515,413 | $ 12,529 | $ 527,982 |
| Restricted common stock issued | 736,780 | — | — | — | — |
| Restricted common stock forfeited | (80,338) | — | — | — | — |
| Restricted stock used for tax withholdings | (18,490) | — | (467) | — | (467) |
| Offering costs related to sale of common stock | — | — | (3) | — | (3) |
| Stock-based compensation | — | — | 4,483 | — | 4,483 |
| Net Income | — | — | — | 46,523 | 46,523 |
| Balances, December 31, 2012 | 40,115,536 | $ 40 | $ 519,426 | $ 59,052 | $ 578,518 |
| Restricted common stock issued, net of excess income tax benefit | 310,439 | — | 128 | — | 128 |
| Restricted common stock forfeited | (31,817) | — | — | — | — |
| Restricted stock used for tax withholdings | (108,239) | — | (4,440) | — | (4,440) |
| Stock-based compensation | — | — | 12,638 | — | 12,638 |
| Net Income | — | — | — | 69,184 | 69,184 |
| Balances, December 31, 2013 | 40,285,919 | $ 40 | $ 527,752 | $ 128,236 | $ 656,028 |
| Restricted common stock issued, net of excess income tax benefit | 309,458 | — | — | — | — |
| Restricted common stock forfeited | (31,597) | — | — | — | — |
| Restricted stock used for tax withholdings | (130,002) | — | (6,007) | — | (6,007) |
| Stock-based compensation | — | — | 20,716 | — | 20,716 |
| Stock issued upon acquisition of oil and gas properties | 853,492 | 1 | 49,050 | — | 49,051 |
| Net Income | — | — | — | 20,283 | 20,283 |
| Balances, December 31, 2014 | 41,287,270 | $ 41 | $ 591,511 | $ 148,519 | $ 740,071 |

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOIDATED STATEMENTS OF CASH FLOWS

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Cash flows from operating activities: | | | |
| Net income | $ 20,283 | $ 69,184 | $ 46,523 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Depreciation, depletion and amortization | 228,856 | 140,547 | 68,445 |
| Deferred income taxes | 12,986 | 42,432 | 30,772 |
| Impairment of oil and gas properties | 167,592 | — | 2,259 |
| Stock-based compensation | 20,716 | 12,638 | 4,483 |
| Amortization of deferred financing costs and debt premium | 1,588 | 1,505 | 700 |
| Accretion of contractual obligation for land acquisition | 1,153 | 761 | 317 |
| Derivative (gain) loss | (121,615) | 12,472 | (924) |
| Abandoned lease and dry hole expense | — | 1,709 | 8,379 |
| Gain on sale of oil and gas properties | (5,322) | — | (4,192) |
| Other | (12) | (8) | 169 |
| Changes in current assets and liabilities: | | | |
| Accounts receivable | (21,376) | (26,315) | (20,738) |
| Prepaid expenses and other assets | (10,884) | 1,394 | (1,164) |
| Accounts payable and accrued liabilities | 35,392 | 50,897 | 22,769 |
| Excess income tax benefit from the vesting of stock awards | — | (128) | — |
| Settlement of asset retirement obligations | (1,637) | (73) | (162) |
| Net cash provided by operating activities | 327,720 | 307,015 | 157,636 |
| Cash flows from investing activities: | | | |
| Acquisition of oil and gas properties | (179,566) | (13,797) | (13,920) |
| Deposits for acquisitions | (1,549) | — | — |
| Proceeds from sale of oil and gas properties | 6,700 | — | 9,337 |
| Payments of contractual obligations | (12,000) | (12,000) | — |
| Exploration and development of oil and gas properties | (641,204) | (417,835) | (281,327) |
| Natural gas plant capital expenditures | (282) | (5,202) | (15,788) |
| Derivative cash settlements | 12,238 | (11,330) | (725) |
| Decrease (increase) in restricted cash | (3,062) | 79 | 253 |
| Additions to property and equipment—non oil and gas | (6,269) | (5,138) | (3,107) |
| Net cash used in investing activities | (824,994) | (465,223) | (305,277) |
| Cash flows from financing activities: | | | |
| Proceeds from credit facility | 263,000 | 102,000 | 151,400 |
| Payments to credit facility | (230,000) | (260,000) | — |
| Proceeds from Senior Notes | 300,000 | 500,000 | — |
| Offering costs related to the sale of Senior Notes | (7,070) | (11,721) | — |
| Payment of employee tax withholdings in exchange for the return of common stock | (6,007) | (4,440) | (467) |
| Deferred financing costs | (647) | (445) | (1,111) |
| Premium on Senior Notes | — | 9,000 | — |

| | | | |
|---|---|---|---|
| Excess income tax benefit from the vesting of stock awards | — | 128 | — |
| Offering costs related to sale of common stock | — | — | (3) |
| Net cash provided by financing activities | 319,276 | 334,522 | 149,819 |
| Net increase (decrease) in cash and cash equivalents | (177,998) | 176,314 | 2,178 |
| Cash and cash equivalents at beginning of period | 180,582 | 4,268 | 2,090 |
| Cash and cash equivalents at end of period | $ 2,584 | $ 180,582 | $ 4,268 |
| Supplemental schedule of additional cash flow information and non-cash investing and financing activities: | | | |
| Cash paid for interest | $ 36,325 | $ 12,860 | $ 2,914 |
| Stock issued for the acquisition of oil and gas properties | $ 49,050 | $ — | $ — |
| Cash paid for income taxes | $ 1,400 | $ 100 | $ 400 |
| Contractual obligation for land acquisition | $ 22,033 | $ 33,272 | $ 45,272 |
| Changes in working capital related to drilling expenditures and property acquisition | $ 1,873 | $ 29,273 | $ 37,545 |

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

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NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations

Bonanza Creek Energy, Inc. (the “Company” or “BCEI”) is engaged primarily in acquiring, developing, exploiting and producing oil and gas properties. As of December 31, 2014, the Company’s assets and operations are concentrated primarily in the Wattenberg Field in the Rocky Mountains and in the Dorcheat Macedonia Field in southern Arkansas.

Basis of Presentation

The consolidated balance sheet includes the accounts of the Company and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Bonanza Creek Energy Resources, LLC, Bonanza Creek Energy Upstream, LLC, Bonanza Creek Energy Midstream, LLC and Holmes Eastern Company, LLC. All significant intercompany accounts and transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2014, through the filing date of this report.

Use of Estimates

The preparation of the Company’s consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturity dates of three months or less to be cash equivalents. The carrying value and cash and cash equivalents approximate fair value due to the short term nature of these instruments.

Accounts Receivable

The Company’s accounts receivables are generated from oil and gas sales and from joint interest owners on properties that the Company operates. The Company accrues an allowance on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any allowance may be reasonably estimated. For receivables from joint interest owners, the Company usually has the ability to withhold future revenue disbursements to satisfy the outstanding balance. The Company’s oil and gas receivables are typically collected within one to two months and the Company has experienced minimal bad debts.

Inventory of Oilfield Equipment

Inventory consists of material and supplies used in connection with the Company’s drilling program. These inventories are stated at the lower of cost or market, which approximates fair value.

Oil and Gas Producing Activities

The Company follows the successful efforts method of accounting for its oil and gas exploration and development costs. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells will be capitalized at cost when incurred, pending determination of whether economically recoverable reserves have been found. If an exploratory well does not find economically recoverable reserves, the costs of drilling the well and other associated costs are charged to dry hole expense. The costs of development wells are capitalized whether the well is productive or nonproductive. Costs incurred to maintain wells and their related equipment and leases as well as operating costs are charged to expense as incurred. Geological and geophysical costs are expensed as incurred.

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Depletion, depreciation and amortization ("DD&A") of capitalized costs of proved oil and gas properties are provided for on a field by field basis using the units of production method based upon proved reserves.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property is written down to fair value. The factors used to determine fair value are subject to the Company's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows on all developed proved reserves and risk adjusted proved undeveloped, probable and possible reserves, net of estimated operating and development costs, future commodity pricing based on the NYMEX strip price adjusted for basis differential, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected.

The Company assesses its unproved properties periodically for impairment on a property by property basis, which requires significant judgment. The Company considers the following factors in its assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under leases;
- its ability to actively manage and prioritize its capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- its ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- its ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and
- its evaluation of the continuing successful results from the application of completion technology in the Niobrara formation by the Company or by other operators in areas adjacent to or near its unproved properties.

Please refer to Note 4—Impairments for additional discussion.

The Company records the fair value of an asset retirement obligation as an asset and a liability when there is a legal obligation associated with the retirement of a long lived asset and the amount can be reasonably estimated. The increase in carrying value is included in proved properties in the accompanying consolidated balance sheets ("accompanying balance sheets"). For additional discussion, please refer to Note 11—Asset Retirement Obligations.

Gains and losses arising from sales of oil and gas properties will be included in income. However, a partial sale of proved properties within an existing field that does not significantly affect the unit of production depletion rate will be accounted for as a normal retirement with no gain or loss recognized. The sale of a partial interest within a proved property is accounted for as a recovery of cost. The partial sale of unproved property is accounted for as a recovery of cost when there is uncertainty of the ultimate recovery of the cost applicable to the interest retained.

Natural Gas Plants

Natural gas plants are recorded at cost and depreciated using the straight line method over a 30 year useful life. The Company assesses the facilities for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable and an impairment loss is recorded as necessary.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Cost of renewals and improvements that substantially extend the useful lives of the assets

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are capitalized. Maintenance and repair costs are expensed as incurred. Depreciation is calculated using the straight line method over the estimated useful lives of the assets, which range from three to ten years.

Assets Held for Sale

Any properties deemed held for sale as of the balance sheet date are presented separately on the accompanying balance sheets at the lower of net book value or fair value less cost to sell. The Company has no assets held for sale at December 31, 2014. At December 31, 2013 the Company had its legacy California assets as held for sale, which is shown within the discontinued operation section of the accompanying consolidated statements of operations and comprehensive income ("accompanying statements of operations") within Note 3—Discontinued Operations.

Revenue Recognition

The Company records revenues, net of royalties, discounts, and allowances, as applicable, from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. Payment is generally received within 30 to 90 days after the date of production. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. At the end of each month the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company factors in historical performance, quality and transportation differentials, commodity prices, and other factors when deriving revenue estimates. The Company has interests with other producers in certain properties in which case the Company uses the entitlement method to account for gas imbalances. The Company had no gas imbalances as of December 31, 2014, 2013 and 2012.

For gathering and processing services, the Company either receives fees or commodities from natural gas producers depending on the type of contract. Under the percentage of proceeds contract type, the Company is paid for its services by keeping a percentage of the NGL produced and a percentage of the residue gas resulting from processing the natural gas. Commodities received are, in turn, sold and recognized as revenue in accordance with the criteria outlined above.

Income Taxes

The Company accounts for income taxes under the liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the balance sheet or tax returns. Under this method, deferred tax assets and liabilities are determined based on the difference between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

Uncertain Tax Positions

The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The tax returns for 2013, 2012 and 2011 are still subject to audit by the Internal Revenue Service. There were no uncertain tax positions.

Concentrations of Credit Risk

The Company has maintained cash balances in excess of the Federal Deposit Insurance Corporation (FDIC) insured limit.

The Company is exposed to credit risk in the event of nonpayment by counterparties whose creditworthiness is continuously evaluated. For the years ended December 31, 2014, 2013 and 2012 Plains Marketing LP accounted for

29%, 37% and 50%, respectively, while Lion Oil Trading & Transportation, Inc. accounted for 19%, 23% and 32%, respectively, of oil and natural gas sales. For the years ended December 31, 2014 and 2013, High Sierra Crude Oil & Marketing accounted for 11% and 15%, respectively, of oil and natural gas sales and an immaterial amount for the year ended December 31, 2012.

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Oil and Gas Derivative Activities

The Company is exposed to commodity price risk related to oil and gas prices. To mitigate this risk, the Company enters into oil and gas forward contracts. The contracts, which are generally placed with major financial institutions or with counterparties which management believes to be of high credit quality, may take the form of futures contracts, swaps, options, or collars. The oil contracts are indexed to NYMEX WTI prices, and natural gas contracts are indexed to NYMEX HH prices, which have a high degree of historical correlation with actual prices received by the Company, before differentials. The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value. For additional discussion, please refer to Note 13—Derivatives.

Earnings Per Share

Earnings per basic and diluted share are calculated under the two class method. Pursuant to the two class method, the Company's unvested restricted stock awards with non forfeitable rights to dividends are considered participating securities. Under the two class method, earnings per basic share is calculated by dividing net income available to shareholders by the weighted average number of common shares outstanding during the period. The two class method includes an earnings allocation formula that determines earnings per share for each participating security according to undistributed earnings for the period. Net income available to shareholders is reduced by the amount allocated to participating restricted shares to arrive at the earnings allocated to common stock shareholders for purposes of calculating earnings per share. Earnings per diluted share is computed on the basis of the weighted average number of common shares outstanding during the period plus the dilutive effect of any potential common shares outstanding during the period using the more dilutive of the treasury method or two class method. For additional discussion, please refer to Note 14—Earnings Per Share.

Stock Based Compensation

The Company measures the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. For additional discussion, please refer to Note 9—Stock Based Compensation.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, trade receivables, trade payables, accrued liabilities, a revolving credit facility, senior notes, and derivative instruments. Cash and cash equivalents, trade receivables, trade payables and accrued liabilities are carried at cost and approximate fair value due to the short term nature of these instruments. Our revolving credit facility has a variable interest rate so it approximates fair value. Our senior notes are recorded at cost, and their fair value is disclosed within Note 12—Fair Value Measurements. Derivative instruments are recorded at fair value. The book value of the contractual obligation for land acquisition approximates fair value due to it being discounted at a market-based interest rate.

Prior Year Reclassifications

Certain prior year balances have been reclassified to conform to the current year presentation, and such reclassifications had no impact on net income or stockholders' equity previously reported.

Recently Issued Accounting Standards

In April 2014, the FASB issued Update No. 2014-08 - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The update is aimed at reducing the frequency of disposals reported as discontinued operations by focusing on strategic shifts that have or will have a major effect on an entity's operations and financial results. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2014 and is to be applied prospectively. This guidance will be applied by the Company upon future disposal of assets on a prospective basis.

In May 2014, the FASB issued Update No. 2014-09 - Revenue From Contracts With Customers. The update prescribes two acceptable methods and is effective for the annual period beginning after December 15, 2016, including interim periods within that reporting period. The Company is currently evaluating the provisions of this guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In June 2014, the FASB issued Update No. 2014-12 - Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could be Achieved after the Requisite Service Period. The guidance relates to the recognition of share-based compensation when an award provides that a performance target can be achieved after the requisite service period. This authoritative accounting guidance may be applied either prospectively or retrospectively and is effective for annual periods and interim periods beginning after December 15, 2015. The Company is currently evaluating the provisions of this guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In August 2014, the FASB issued Update No. 2014-15 - Presentation of Financial Statements – Going Concern that requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity's ability to continue as a going concern within one year after the date that the entity's financial statements are issued, or within one year after the date that the entity's financial statements are available to be issued, and to provide disclosures when certain criteria are met. This guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In November 2014, the FASB issued Update No. 2014-17 – Business Combinations – Pushdown Accounting that gives an acquired entity an option to apply pushdown accounting in its separate financial statements upon occurrence of an event in which an acquirer obtains control of the acquired entity. This guidance was effective on November 18, 2014 for any future change-in-control event. This guidance will be applied by the Company if we were to experience a change-in-control.

NOTE 2—ACQUISITIONS

In July 2014, the Company acquired approximately 34,000 net acres of oil and gas properties, leasehold mineral interests and related assets located in the Wattenberg Field ("Wattenberg Field Acquisition") from a private operator. The Company paid approximately $174.6 million (inclusive of customary acquisition costs) in cash and issued 853,492 shares of the Company's common stock valued at $57.47 per share, the market price at the time of closing, for the acquired assets. The Wattenberg Field Acquisition had an effective date of June 1, 2014 and closed on July 8, 2014. The results of operations for the Wattenberg Field Acquisition have been included in the Company's consolidated financial statements from the date of closing. Pro forma information is not presented as the pro forma results would not have been materially different from the information presented in the accompanying statements of operations.

The Wattenberg Field Acquisition was recorded using the purchase method of accounting. The following table summarizes the allocation of consideration paid (inclusive of customary acquisition costs) to the tangible assets acquired and liabilities assumed in the Wattenberg Field Acquisition.

| | Asset Valuation Amount (in thousands) |
|---|---|
| Purchase price (1) | $ 223,678 |
| | |
| Allocation of purchase price: | |
| Proved properties | $ 25,014 |
| Unproved properties | 198,757 |
| Asset retirement obligation | (93) |
| Total | $ 223,678 |

On July 31, 2012, the Company acquired leases to approximately 5,600 net acres in the Wattenberg Field from the State of Colorado, State Board of Land Commissioners. The Company paid approximately $12 million at closing,

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$12 million in July 2013 and $12 million in July 2014. The Company will pay approximately $12 million in July 2015 and July 2016. The future payments were discounted based on our effective borrowing rate to arrive at the purchase price of $57 million. Future payments include imputed interest and are secured by a $24 million letter of credit. Following each payment the amount secured by the letter of credit will be amended to reflect the reduction in obligation.

NOTE 3—DISCONTINUED OPERATIONS

During June of 2012, the Company began marketing, with the intent to sell, all of its oil and gas properties in California classifying them as assets held for sale. Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. The Company determined that its intent to sell all of its assets in a region qualified as discontinued operations. The Company sold a majority of the properties for approximately $9.3 million and recorded a gain on the sale of oil and gas properties in the amount of $4.2 million during 2012. The Company sold its remaining property during the first quarter of 2014 for approximately $6.0 million and recorded a gain on the sale of oil and gas properties in the amount of $5.5 million. The carrying amounts of the remaining property included within assets held for sale classified as discontinued operations are presented below.

| | As of December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Assets held for sale: | | |
| Oil and gas properties, successful efforts method: | | |
| Proved properties | $ — | $ 1,721 |
| Unproved properties | — | 1 |
| Wells in progress | — | 101 |
| Total property and equipment | — | 1,823 |
| Less accumulated depletion, depreciation, and amortization | — | (1,463) |
| Net property and equipment | $ — | $ 360 |

The current assets and liabilities related to these properties are immaterial. The total revenues, expenses, and income associated with the operation of the oil and gas properties held for sale as discontinued operations are presented below.

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Net revenues: | | | |
| Oil and gas sales | $ 361 | $ 1,668 | $ 5,410 |
| Operating expenses: | | | |
| Lease operating expense | 366 | 1,870 | 2,280 |
| Severance and ad valorem taxes | 13 | 5 | 127 |

| | | | |
|---|---|---|---|
| Exploration | — | 66 | 39 |
| Depreciation, depletion and amortization | 67 | 371 | 2,243 |
| Impairment of oil and gas properties | — | — | 1,648 |
| Total operating expenses | 446 | 2,312 | 6,337 |
| Loss from operations associated with oil and gas properties held for sale | $ (85) | $ (644) | $ (927) |

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NOTE 4—IMPAIRMENTS

For the year ended December 31, 2014, the Company recorded proved property impairments of $127.3 million in the Dorcheat Macedonia Field, due to low commodity prices, $25.0 million of proved property impairments in the McKamie Patton Field due to low commodity prices and natural field decline, and $15.3 million of proved property impairments in the McCallum Field due to low commodity prices.

The Company recorded no proved property impairments in 2013. For the year ended December 31, 2012, the Company recorded $611,000 of proved property impairments from continuing operations located in one of the Company's non core southern Arkansas fields and $1.6 million of proved property impairments from discontinued operations located in the Company's legacy California assets. The impairments of the Company's legacy assets in California were related to steam flooding results that were lower than expected and the impairment of the non core field in southern Arkansas was related to the loss of a lease.

NOTE 5—OTHER ASSETS

The Company has multiple certificates of deposit at three financial institutions to meet financial bonding requirements in the states of Colorado and Wyoming.

The Company has unamortized deferred financing costs related to the bank revolving credit agreement and Senior Notes issuances.

| | As of December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Certificates of deposit | $ 228 | $ 166 |
| Restricted cash | 3,000 | — |
| Deposit for acquisition of oil and gas properties | 1,549 | — |
| Deferred financing costs | 18,595 | 13,693 |
| Other noncurrent assets | $ 23,372 | $ 13,859 |

NOTE 6—ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses contain the following:

| | As of December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Drilling and completion costs | $ 82,844 | $ 80,971 |
| Accounts payable trade | 5,493 | 3,288 |
| Accrued general and administrative cost | 13,541 | 12,720 |
| Lease operating expense | 3,569 | 5,440 |
| Accrued reclamation cost | 162 | 168 |
| Interest | 14,839 | 7,065 |
| Accrued oil and gas derivatives | — | 446 |
| Production and ad valorem taxes and other | 25,340 | 11,567 |

| | | |
|---|---|---|
| Total accounts payable and accrued expenses | $ 145,788 | $ 121,665 |

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NOTE 7—LONG TERM DEBT

Long term debt consisted of the following as of December 31, 2014 and 2013:

| | As of December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Revolving credit facility | $ 33,000 | $ — |
| 6.75% Senior Notes due 2021 | 500,000 | 500,000 |
| Unamortized premium on 6.75% Senior Notes | 7,619 | 8,847 |
| 5.75% Senior Notes due 2023 | 300,000 | — |
| Total long-term debt | $ 840,619 | $ 508,847 |

Revolving Credit Facility

The revolving credit facility, dated March 29, 2011, as amended, with a syndication of banks, including KeyBank National Association as the administrative agent and issuing lender, provides for borrowings of up to $1 billion. The revolving credit facility provides for interest rates plus an applicable margin to be determined based on LIBOR or a Base Rate, at the Company's election. LIBOR borrowings bear interest at LIBOR plus 1.50% to 2.50% depending on the utilization level, and the Base Rate borrowings bear interest at the "Bank Prime Rate," as defined in the revolving credit facility, plus .50% to 1.50%.

On September 30, 2014 the borrowing base under the revolving credit facility was determined to be $600 million, an increase from $450 million (decreased from $525 million following the July 2014 issuance of the Company's 5.75% Senior Notes). Pursuant to the corresponding amendment, the Company elected to limit bank commitments at $500 million while reserving the option to access, at the Company's request, the full $600 million prior to the next semi annual redetermination. The borrowing base is re determined semiannually on May 15 and November 15 and may be re determined up to one additional time between such scheduled determinations upon request by the Company or lenders holding $66^2/_3$% of the aggregate commitments. Commitment fees on the revolving credit facility range from 0.375% to 0.50%, depending on utilization. The revolving credit facility is collateralized by substantially all the Company's assets and matures on September 15, 2018. As of December 31, 2014, the Company had $33 million outstanding under the revolving credit facility with an available borrowing capacity of $543 million, if the Company elected to take advantage of the entire borrowing base (without giving effect to any scheduled or interim redetermination), after reduction for the outstanding letter of credit of $24 million. As of December 31, 2013, the Company had no outstanding balance under the revolving credit facility with $414 million available borrowing capacity after reduction for the outstanding letter of credit of $36 million. As of the filing date of this report, the Company had no outstanding balance under the revolving credit facility, with $576 million available borrowing capacity, if the Company elected to take advantage of the entire borrowing base (without giving effect to any scheduled or interim redetermination), after reduction for the outstanding letter of credit of $24 million. For additional discussion on the letter of credit, please refer to Note 2 – Acquisitions.

The revolving credit facility restricts, among other items, the payment of dividends, certain additional indebtedness, sale of assets, loans and certain investments and mergers. The revolving credit facility also contains certain financial covenants, which require the maintenance of a minimum current and debt coverage ratios, as defined by the revolving credit facility. The Company was in compliance with all financial and non financial covenants as of December 31, 2014 and through the filing date of this report.

5.75% Senior Notes

On July 15, 2014, the Company issued $300 million aggregate principal amount of 5.75% Senior Notes that mature on February 1, 2023. Interest on the 5.75% Senior Notes began accruing on July 15, 2014, and interest is payable on February 1 and August 1 of each year, beginning on February 1, 2015. The 5.75% Senior Notes are guaranteed on a senior unsecured basis by the Company's existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under the revolving credit facility. The net proceeds from the sale of the 5.75% Senior Notes were $293.4 million after deductions of $6.6 million of expenses and underwriting discounts and commissions. The net proceeds were used to pay off the Company's outstanding credit facility balance and for general corporate purposes, including the Company's drilling and development program and other capital expenditures.

At any time prior to August 1, 2017, subject to certain limitations, the Company may redeem up to 35% of the aggregate principal amount of the 5.75% Senior Notes at a redemption price of 105.75% of the principal amount, plus accrued and unpaid interest, with an amount of cash not greater than the net cash proceeds of an equity offering. The Company may redeem all or a part of the 5.75% Senior Notes at any time prior to August 1, 2018 subject to a "make-whole" premium and accrued and unpaid interest. On or after August 1, 2018, the Company may redeem all or a part of the 5.75% Senior Notes at the redemption price of 102.875% for 2018, 101.438% for 2019, and 100.0% for 2020 and thereafter, during the twelve month period beginning on August 1 of each applicable year, in each case, plus accrued and unpaid interest.

6.75% Senior Notes

On April 9, 2013, the Company issued $300 million aggregate principal amount of 6.75% Senior Notes that mature on April 15, 2021. Interest on the Senior Notes began accruing on April 9, 2013, and interest is payable on April 15 and October 15 of each year, which began on October 15, 2013. On November 15, 2013, the Company issued an additional $200 million aggregate principal amount of 6.75% Senior Notes as an additional issuance of its existing 6.75% Senior Notes that mature on April 15, 2021. The 6.75% Senior Notes are guaranteed on a senior unsecured basis by the Company's existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under the Company's revolving credit facility. The net proceeds from the sale of the 6.75% Senior Notes were $496.8 million after the premium and deduction of $12.2 million of expenses and underwriting discounts and commissions. The net proceeds were used to pay off the Company's outstanding credit facility balance and for general corporate purposes, including the Company's drilling and development program and other capital expenditures.

At any time prior to April 15, 2016, the Company may redeem up to 35% of the aggregate principal amount at a redemption price of 106.75% of the principal amount, plus accrued and unpaid interest. The Company may redeem all or a part of the 6.75% Senior Notes at any time prior to April 15, 2017 at the redemption price equal to 100% of the principal amount, plus the applicable "make whole" premium and accrued and unpaid interest. On or after April 15, 2017, the Company may redeem all or a part of the 6.75% Senior Notes at the redemption price of 103.375% for 2017, 101.688% for 2018, and 100.0% for 2019 and thereafter, during the twelve month period beginning on April 15 of each applicable year, plus accrued and unpaid interest.

On November 12, 2013 and July 15, 2014, the Company filed automatic registration statements on Form S 3 to register the Senior Notes and guarantees of the Senior Notes. As of December 31, 2014, all of the existing subsidiaries of the Company are guarantors of the 5.75% Senior Notes and 6.75% Senior Notes, and all such subsidiaries are 100% owned by the Company. The guarantees by the subsidiaries are full and unconditional (except for customary release provisions) and constitute joint and several obligations of the subsidiaries. The Company has no independent assets or operations unrelated to its investments in its consolidated subsidiaries. There are no significant restrictions on the Company's ability or the ability of any subsidiary guarantor to obtain funds from its subsidiaries by such means as a dividend or loan.

NOTE 8—COMMITMENTS AND CONTINGENT LIABILITIES

Contingent Liabilities

From time to time, the Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. In accordance with accounting authoritative guidance, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal

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theories, and/or the ongoing discovery and development of information important to the matters. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. No claims have been made, nor is the Company aware of any material uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations. As of the date of this filing, there were no material pending or overtly threatened legal actions against the Company of which it is aware.

Commitments

In October 2014, the Company entered into two purchase and transportation agreements to deliver fixed determinable quantities of crude oil currently anticipated to take effect during the second quarter of 2015 for 12,580 barrels per day over an initial five year term and the third quarter of 2016 for 15,000 barrels per day over an initial seven year term. The aggregate financial commitment fee is approximately $540 million over the initial terms. While the volume commitment may be met with Company volumes or third party volumes, delegated by the Company, the Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments.

The Company rents office facilities under various non cancelable operating lease agreements. The annual minimum payments on the transportation and operating lease agreements for the next five years and total minimum lease payments thereafter are presented below:

| | Commitments (in thousands) |
|---|---|
| 2015 | $ 38,441 |
| 2016 | 68,878 |
| 2017 | 91,916 |
| 2018 | 91,990 |
| 2019 | 92,056 |
| 2020 and thereafter | 170,132 |
| Total | $ 553,413 |

The Company's office leases extend through 2020. Rent expense for the years ended December 31, 2014, 2013 and 2012 was $2.0 million, $1.4 million and $886,000, respectively.

NOTE 9—STOCK BASED COMPENSATION

Management Incentive Plan

On December 23, 2010, the Company established the Management Incentive Plan (the "Plan") for the benefit of certain employees, officers and other individuals performing services for the Company. The maximum number of shares of Class B common stock available under the Plan was 10,000 and these shares were converted into 437,787 shares of our restricted common stock upon completion of the Company's initial public offering. The conversion rate was determined based on a formula factoring in the rate of return to the pre IPO common stockholders. The 437,787 shares of common stock that were granted were valued at the IPO stated price of $17.00 per share and vested over a three year period. Stock based compensation expense of $4.8 million, $2.5 million and $2.5 million was recorded during the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014, all common stock granted under the plan was fully vested with no unrecognized compensation remaining.

BCEC Investment Trust

The BCEC Investment Trust was formed to hold shares of our common stock received by Bonanza Creek Energy Company, LLC, our predecessor, in connection with our December 23, 2010 corporate restructuring. On February 5, 2013, 13,825 previously issued shares of our common stock that were fully vested and held by the BCEC Investment Trust were distributed to former employees. While the shares had been issued in December 2010, for accounting purposes, the date of distribution to former employees was considered the grant date, and these shares were valued at the closing price of our common stock on the grant date, which was $34.18 per share. On February 11, 2013,

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59,372 previously issued shares of our common stock that were fully vested and held by the BCEC Investment Trust were distributed to certain then current employees. While the shares had been issued in December 2010, for accounting purposes, the date of distribution to employees was considered the grant date, and these shares were valued at the closing price of our common stock on the grant date, which was $34.89 per share. These distributions resulted in a stock based compensation expense of $2.5 million for the year ended December 31, 2013.

Long Term Incentive Plan

The Company's 2011 Long Term Incentive Plan has different forms of equity issuances allowed under it as further described in this section.

Restricted Stock under the Long Term Incentive Plan

The Company grants shares of restricted stock to directors, eligible employees and officers as a part of its equity incentive plan. Restrictions and vesting periods for the awards are determined by the Compensation Committee of the Board of Directors and are set forth in the award agreements. Each share of restricted stock represents one share of the Company's common stock to be released from restrictions upon completion of the vesting period. The awards typically vest in one third increments over three years. Each share of restricted stock is entitled to a non forfeitable dividend, if the Company were to declare one, and has the same voting rights as a share of common stock. Shares of restricted stock are valued at the closing price of the Company's common stock on the grant date and are recognized as general and administrative expense over the vesting period of the award.

The Company granted 297,030, 292,396 and 697,500 shares of restricted stock under the LTIP to certain employees during 2014, 2013 and 2012, respectively. The fair value of the restricted stock granted in 2014, 2013 and 2012 was $13.9 million, $12.4 million and $11.8 million, respectively. The Company recognized compensation expense of $13.9 million, $6.9 million and $1.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014 unrecognized compensation cost was $15.6 million and will be amortized through 2017.

In 2014, 2013 and 2012, the Company issued 12,919, 18,043 and 33,534 shares, respectively, of restricted common stock under the LTIP to its non employee directors. The Company recognized compensation expense of $734,000, $445,000 and $267,000 for the years ended December 31, 2014, 2013 and 2012, respectively. These awards vest approximately one year after issuance.

A summary of the status and activity of non vested restricted stock is presented below:

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2014 | | 2013 | | 2012 | |
| | Restricted Stock | Weighted-Average Grant-Date Fair Value | Restricted Stock | Weighted-Average Grant-Date Fair Value | Restricted Stock | Weighted-Average Grant-Date Fair Value |
| Non-vested at beginning of year | 836,002 | $ 25.11 | 929,336 | $ 17.06 | 437,787 | $ 17.00 |
| Granted | 309,949 | $ 45.87 | 310,439 | $ 39.89 | 731,034 | $ 16.98 |
| Vested | (524,818) | $ 25.95 | (371,956) | $ 17.44 | (159,147) | $ 17.11 |
| Forfeited | (31,604) | $ 32.73 | (31,817) | $ 24.09 | (80,338) | $ 15.89 |
| Non-vested at end of year | 589,529 | $ 37.66 | 836,002 | $ 25.11 | 929,336 | $ 17.06 |

Cash flows resulting from excess tax benefits are to be classified as part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for vested restricted stock in excess of the deferred tax asset attributable to stock compensation costs for such restricted stock. The Company recorded no excess tax benefits for the years ended December 31, 2014 and 2012. The Company recorded $127,830 for the year ended December 31, 2013 as cash inflows from financing activities.

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Performance Stock Units under the Long Term Incentive Plan

The Company grants performance stock units ("PSUs") to certain officers as part of its LTIP. The number of shares of the Company's common stock that may be issued to settle PSUs ranges from zero to two times the number of PSUs awarded. PSUs granted prior to 2014 are determined based on the Company's performance over a three year measurement period and vest in their entirety, if at all, at the end of the measurement period. Satisfaction of the performance conditions for the PSUs granted during 2014 are determined at the end of each annual measurement period over the course of the three-year performance cycle in an amount up to two-thirds of the target number of PSUs that are eligible for vesting (such that an amount equal to 200% of the target number of PSUs may be earned during the performance cycle). For all grants, the PSUs will be settled in shares of the Company's common stock following the end of the three-year performance cycle. Any PSUs that have not vested at the end of the applicable measurement period are forfeited. The performance criterion for the PSUs is based on a comparison of the Company's Total Shareholder Return ("TSR") for the measurement period compared with the TSRs of a group of peer companies for the measurement period. Compensation expense associated with PSUs is recognized as general and administrative expense over the measurement period.

The fair value of the PSUs was measured at the grant date with a stochastic process method using the GBM Model. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, risk free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period, as well as the volatilities for each of the Company's peers.

During 2014 and 2013, the Company granted 82,312 and 41,622 PSUs, respectively, under the LTIP to certain officers. The fair value of the PSUs granted in 2014 and 2013 was $3.5 million and $1.2 million, respectively. The Company recognized compensation expense of $1.3 million and $340,000 for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014, unrecognized compensation expense for PSUs was $3.1 million and will be amortized through 2017.

A summary of the status and activity of non-vested PSUs is presented in the following table:

| | For the Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2014 | | 2013 | |
| | PSU | Weighted-Average Grant Date Fair Value | PSU | Weighted-Average Grant Date Fair Value |
| Non-vested at beginning of year(1) | 40,191 | $ 32.05 | — | $ — |
| Granted(1) | 82,312 | $ 41.94 | 41,622 | $ 32.01 |

| | | | | |
|---|---|---|---|---|
| Vested(2) | (28,330) | $ 42.50 | — | $ — |
| Forfeited(1) | — | $ — | (1,431) | $ 30.85 |
| Non-vested at end of year(1) | 94,173 | $ 37.55 | 40,191 | $ 32.05 |

(1) The number of awards assumes that the associated performance condition is met at the target amount. The final number of shares of common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the performance condition.

(2) For the annual measurement period ending December 31, 2014, the 2014 PSU grant vested at a 1.33 multiplier and the earned shares will be released at the end of the three-year performance cycle.

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401(k) Plan

The Company has a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to the contribution limits established under the IRC. The Company matches each employee's contribution up to six percent of the employee's base salary. The Company's matching contributions to the 401(k) Plan were $1.4 million, $837,000, and $589,000 for the years ended December 31, 2014, 2013 and 2012, respectively.

NOTE 10—INCOME TAXES

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax bases of assets and liabilities and amounts reported in the Company's balance sheet. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liabilities determines the periodic provision for deferred taxes. The provision for income taxes consists of the following:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Current tax expense | | | |
| Federal | $ 165 | $ 122 | $ 289 |
| State | (16) | 126 | 243 |
| Deferred tax expense | 12,986 | 42,432 | 30,772 |
| Total income tax expense | $ 13,135 | $ 42,680 | $ 31,304 |

Temporary differences between the financial statement carrying amounts and tax bases of assets and liabilities that give rise to the net deferred tax liability result from the following components:

| | As of December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Deferred tax liabilities: | | |
| Oil and gas properties | $ 201,635 | $ 195,776 |
| Derivative asset | 40,060 | — |
| Total deferred tax liabilities | 241,695 | 195,776 |
| Deferred tax assets: | | |
| Federal and state tax net operating loss carryforward | 59,952 | 31,289 |
| Reclamation costs | 8,344 | 4,311 |
| Stock compensation | 3,845 | 2,617 |
| Derivative liability | — | 1,833 |
| AMT credit | 812 | 776 |
| State bonus depreciation addback | 2,083 | 1,938 |
| Other long-term liabilities | 992 | 331 |
| Total deferred tax assets | 76,028 | 43,095 |
| Total non-current net deferred tax liability | $ 165,667 | $ 152,681 |

The Company has $177.3 million and $95.1 million of net operating loss carryovers for federal income tax purposes of which $14.5 million and $9.3 million is not recorded as a benefit for financial statement purposes as it relates to tax deductions that are different from the stock based compensation expense recorded for financial statement purposes as of December 31, 2014 and 2013, respectively. The federal net operating loss carryforward begins to expire in 2032. The benefit of these excess tax deductions will not be recognized for financial statement purposes until the related deductions reduce taxes payable.

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Federal income tax expense differs from the amount that would be provided by applying the statutory United States federal income tax rate to income before income taxes primarily due to the effect of state income taxes, rate changes, and other permanent differences, as follows:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Federal statutory tax expense | $ 11,696 | $ 39,152 | $ 27,174 |
| Increase (decrease) in tax resulting from: | | | |
| State tax expense net of federal benefit | 1,106 | 3,834 | 2,753 |
| Rate change and other | 333 | (306) | 1,377 |
| Total income tax expense | $ 13,135 | $ 42,680 | $ 31,304 |

Reconciliation of the Company's effective tax rate to the expected federal tax rate of 35% in 2014, 2013, and 2012 is as follows:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Expected federal tax rate | 35.00 % | 35.00 % | 35.00 % |
| State income taxes | 3.29 % | 3.43 % | 3.55 % |
| Change in tax rate | 1.01 % | (0.28) % | 1.67 % |
| Effective tax rate | 39.30 % | 38.15 % | 40.22 % |

During the year ended December 31, 2014, the increase in tax rate was primarily due to an increase in permanent differences. Total deferred income tax expense in the accompanying statements of operations is $13.0 million.

During the year ended December 31, 2013, the decrease in tax rate was primarily due to a decrease in taxable income apportioned to California and Arkansas and an increase in taxable income apportioned to Colorado. The decrease in the effective tax rate with the change in tax rate was applied to the January 1, 2013 deferred income tax liability resulting in a decrease to the net deferred tax liability and deferred income tax expense of $400,000. The total deferred income tax expense in the accompanying statements of operations was $42.4 million.

During the year ended December 31, 2012, the estimated effective tax rate was revised to reflect a 35% rate for federal income taxes. The Company believed that this rate more appropriately reflected the federal rate on future earnings. The increase in the effective tax rate with the change in tax rate was applied to the January 1, 2012 deferred income tax liability resulting in an increase to the net deferred tax liability and deferred income tax expense of $1.2 million with an additional $29.6 million applicable to federal and state income taxes for the year ended December 31, 2012, which together resulted in a total deferred income tax expense in the accompanying statements of operations of $30.8 million.

The Company had no unrecognized tax benefits as of December 31, 2014, 2013 and 2012.

## NOTE 11—ASSET RETIREMENT OBLIGATIONS

The Company recognizes an estimated liability for future costs to abandon its oil and gas properties. The fair value of the asset retirement obligation is recorded as a liability when incurred, which is typically at the time the asset is acquired or placed in service. There is a corresponding increase to the carrying value of the asset which is included in the proved properties line item in the accompanying balance sheets. The Company depletes the amount added to proved properties and recognizes expense in connection with accretion of the discounted liability over the remaining estimated economic lives of the properties.

The Company's estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimated costs to abandon the wells, and regulatory requirements. The liability is

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discounted using the credit adjusted risk free rate estimated at the time the liability is incurred and ranges from 8% to 11.7%. A reconciliation of the Company's asset retirement obligation is as follows:

| | As of December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Beginning of year | $ 11,218 | $ 7,334 |
| Additional liabilities incurred | 4,190 | 1,067 |
| Accretion expense | 1,382 | 645 |
| Obligations on properties sold | (833) | — |
| Liabilities settled | (557) | (74) |
| Revisions to estimate | 6,226 | 2,246 |
| End of year | $ 21,626 | $ 11,218 |

Revisions to the liability could occur due to changes in the estimated economic lives and abandonment costs of the wells along with newly enacted regulatory requirements. The additional liabilities incurred for the year ended December 31, 2014 primarily came from the drilling and completion of new wells and the Wattenberg Field Acquisition. The revisions to estimates for the year ended December 31, 2014 were a result of decreased estimated economic well lives and an increase in estimated abandonment cost on wells that had an asset retirement obligation as of the beginning of the year.

The Company has approximately $162,000 and $168,000 accrued of asset retirement obligations in accounts payable and accrued expenses on the accompanying balance sheets for the years ended December 31, 2014 and 2013, respectively. For additional discussion, please refer to Note 6—Accounts Payable and Accrued Expenses.

NOTE 12—FAIR VALUE MEASUREMENTS

The Company follows fair value measurement authoritative guidance, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities

Level 2: Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model derived valuations whose inputs are observable or whose significant value drivers are observable

Level 3: Significant inputs to the valuation model are unobservable

Financial assets and liabilities are to be classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

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The following tables present the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 and 2013 and their classification within the fair value hierarchy:

| | As of December 31, 2014 | | |
|---|---|---|---|
| | Level 1 | Level 2 | Level 3 |
| | (in thousands) | | |
| Derivative assets | $ — | $ 104,005 | $ — |
| Derivative liabilities | $ — | $ — | $ — |

| | As of December 31, 2013 | | |
|---|---|---|---|
| | Level 1 | Level 2 | Level 3 |
| | (in thousands) | | |
| Derivative assets | $ — | $ 1,151 | $ — |
| Derivative liabilities | $ — | $ 6,523 | $ — |

Derivatives

Fair value of all derivative instruments are estimated with industry standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. All valuations were compared against counterparty statements to verify the reasonableness of the estimate. The Company's commodity swaps and collars are validated by observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. Presently, all of our derivative arrangements are concentrated with five counterparties all of which are lenders under the Company's revolving credit facility.

For the oil and natural gas derivatives outstanding at December 31, 2014, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2014 would change our derivative gain (loss) by $(17.2) million and $15.3 million, respectively.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs exceed the sum of the undiscounted cash flows. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of risk-adjusted discount rates and price forecasts selected by the Company's management. The calculation of the risk-adjusted discount rate is a significant management estimate based on the best information available. Management believes that the risk-adjusted discount rate is representative of current market conditions and reflects the following factors: estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on the NYMEX strip pricing, adjusted for basis differentials. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above. The Company impaired the Dorcheat Macedonia Field which had a carrying value of $519.2 million to its fair value of $391.9

million and recognized an impairment of $127.3 million for the year ended December 31, 2014. The Company impaired the McKamie Patton Field which had a carrying value of $41.0 million to its fair value of $16.0 million and recognized an impairment of $25.0 million for the year ended December 31, 2014. The Company impaired the McCallum Field which had a carrying value of $15.3 million to its fair value of zero and recognized an impairment of $15.3 for the year ended December 31, 2014. There were no proved properties measured at fair value at December 31, 2013. For additional discussion on impairments, please refer to Note 4 – Impairments.

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Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses Level 3 inputs and the income valuation technique, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company uses the price received for similar acreage in recent transactions by the Company or other market participants in the principal market. There were no unproved properties measured at fair value as of December 31, 2014 and 2013.

Asset Retirement Obligation

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit adjusted risk free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Upon completion of wells and natural gas plants, the Company records an asset retirement obligation at fair value using Level 3 assumptions. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. The Company had $6.2 million of asset retirement obligations recorded at fair value as of December 31, 2014. There were no asset retirement obligations measured at fair value at December 31, 2013.

Long term Debt

As of December 31, 2014, the Company had $500 million of outstanding 6.75% Senior Notes and $300 million of outstanding 5.75% Senior Notes. The 6.75% Senior Notes are recorded at cost net of the unamortized premium on the accompanying balance sheets at $507.6 million and $508.8 million as of December 31, 2014 and 2013, respectively. The fair value of the 6.75% Senior Notes as of December 31, 2014 and 2013 was $440.0 million and $527.5 million, respectively. The 5.75% Senior Notes are recorded at cost on the accompanying balance sheets of $300.0 million. The fair value of the 5.75% Senior Notes as of December 31, 2014 was $243.0 million. The Senior Notes are measured using Level 1 inputs based on a secondary market trading price. The Company's revolving credit facility approximates fair value as the applicable interest rates are floating.

NOTE 13—DERIVATIVES

The Company enters into commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other than trading purposes. The Company's derivatives include swaps and collar arrangements for oil and gas and none of the derivative instruments qualify as having hedging relationships.

In a typical commodity swap agreement, if the agreed upon published third party index price is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. If the index price is below the strike price of our short-puts associated with the Company's three-way collars, the Company will receive a payment from our hedging counterparty equal to the difference between the strike prices of the short-put and long-put multiplied by the monthly volume associated with the three-way collar

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As of December 31, 2014, and as of the filing date of this report, the Company had the following derivative commodity contracts in place:

| Settlement Period | Derivative Instrument | Total Volumes (Bbls/MMBtu per day) | Average Fixed Price | Average Short Floor Price (Short-Put) | Average Floor Price (Long-Put) | Average Ceiling Price | Fair Market Value of Asset (Liability) (in thousands) |
|---|---|---|---|---|---|---|---|
| Oil | | | | | | | |
| 1Q 2015 | Swap | 6,000 | $ 95.39 | | | | $ 22,363 |
| 2Q 2015 | Swap | 5,000 | $ 94.41 | | | | 17,497 |
| 3Q 2015 | Swap | 2,000 | $ 93.43 | | | | 6,534 |
| 4Q 2015 | Swap | 2,000 | $ 93.43 | | | | 6,170 |
| 1Q 2015 | 3-Way Collar | 6,500 | | $ 68.08 | $ 84.32 | $ 95.90 | 9,264 |
| 2Q 2015 | 3-Way Collar | 5,500 | | $ 67.73 | $ 84.09 | $ 95.16 | 7,275 |
| 3Q 2015 | 3-Way Collar | 6,500 | | $ 68.46 | $ 84.62 | $ 95.49 | 7,846 |
| 4Q 2015 | 3-Way Collar | 6,500 | | $ 68.46 | $ 84.62 | $ 95.49 | 7,091 |
| 2016 | 3-Way Collar | 5,500 | | $ 70.00 | $ 85.00 | $ 96.83 | 17,765 |
| | | | | | | | $ 101,805 |
| Gas | | | | | | | |
| 2015 | 3-Way Collar | 15,000 | | $ 3.50 | $ 4.00 | $ 4.75 | $ 2,200 |
| | | | | | | | $ 2,200 |
| Total Derivative Assets and Liabilities Fair Value | | | | | | | $ 104,005 |

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities.

The following table contains a summary of all the Company's derivative positions reported on the accompanying balance sheets as of December 31, 2014 and 2013:

| | As of December 31, 2014 | |
|---|---|---|
| | Balance Sheet Location | Fair Value (in thousands) |
| Derivative Assets | | |
| Commodity contracts | Current assets | 86,240 |
| Commodity contracts | Noncurrent assets | 17,765 |
| Derivative Liabilities | | |

| | | |
|---|---|---|
| Commodity contracts | Current liabilities | — |
| Commodity contracts | Long-term liabilities | — |
| Total net derivative asset | | $ 104,005 |

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| | As of December 31, 2013 | |
|---|---|---|
| | Balance Sheet Location | Fair Value |
| Derivative Assets | | (in thousands) |
| Commodity contracts | Current assets | $ 858 |
| Commodity contracts | Noncurrent assets | 293 |
| Derivative Liabilities | | |
| Commodity contracts | Current liabilities | (5,320) |
| Commodity contracts | Long-term liabilities | (1,203) |
| Total net derivative liability | | $ (5,372) |

The following table summarizes the components of the derivative gain (loss) presented on the accompanying statements of operations:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Derivative cash settlement gain (loss): | | | |
| Oil contracts | $ 11,523 | $ (11,755) | $ (1,492) |
| Gas contracts | 715 | 425 | 767 |
| Total derivative cash settlement gain (loss)(1) | $ 12,238 | $ (11,330) | $ (725) |
| Change in fair value gain (loss): | $ 109,377 | $ (1,142) | $ 1,649 |
| Total derivative gain (loss)(2) | $ 121,615 | $ (12,472) | $ 924 |

(1) Derivative cash settlement gain (loss) is reported in the derivative cash settlements line item on the accompanying consolidated statements of cash flows within the net cash used in investing activities.
(2) Total derivative gain (loss) is reported in the derivative gain (loss) line item on the accompanying consolidated statements of cash flows within the net cash provided by operating activities.

NOTE 14—EARNINGS PER SHARE

The Company issues shares of restricted stock entitling the holders to receive non forfeitable dividends, if and when, the Company were to declare a dividend, before vesting, thus making the awards participating securities. The awards are included in the calculation of earnings per share under the two class method. The two class method allocates earnings for the period between common shareholders and unvested participating shareholders.

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The following table sets forth the calculation of earnings per basic and diluted shares from continuing and discontinued operations for the years ended December 31, 2014, 2013 and 2012:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands, except per share data) | | |
| Income from continuing operations: | | | |
| Income from continuing operations | $ 16,982 | $ 69,582 | $ 44,571 |
| Less: undistributed earnings to unvested restricted stock | 315 | 1,673 | 826 |
| Undistributed earnings to common shareholders | 16,667 | 67,909 | 43,745 |
| Basic income per common share from continuing operations | $ 0.42 | $ 1.73 | $ 1.12 |
| Diluted income per common share from continuing operations | $ 0.41 | $ 1.72 | $ 1.12 |
| Income (loss) from discontinued operations: | | | |
| Income (loss) from discontinued operations | $ 3,301 | $ (398) | $ 1,952 |
| Less: undistributed earnings (loss) to unvested restricted stock | 62 | (10) | 36 |
| Undistributed earnings (loss) to common shareholders | 3,239 | (388) | 1,916 |
| Basic income (loss) per common share from discontinued operations | $ 0.08 | $ (0.01) | $ 0.05 |
| Diluted income (loss) per common share from discontinued operations | $ 0.08 | $ (0.01) | $ 0.05 |
| Net income: | | | |
| Net income | $ 20,283 | $ 69,184 | $ 46,523 |
| Less: undistributed earnings to unvested restricted stock | 377 | 1,663 | 862 |
| Undistributed earnings to common shareholders | 19,906 | 67,521 | 45,661 |
| Basic net income per common share | $ 0.50 | $ 1.72 | $ 1.17 |
| Diluted net income per common share | $ 0.49 | $ 1.71 | $ 1.17 |
| Weighted-average shares outstanding—basic | 40,139 | 39,337 | 39,052 |
| Add: dilutive effect of contingent PSUs | 151 | 66 | — |
| Weighted-average shares outstanding—diluted | 40,290 | 39,403 | 39,052 |

The Company had no anti dilutive shares for the years ended December 31, 2014, 2013 and 2012.

NOTE 15-SUBSEQUENT EVENTS

Equity Issuance

On February 6, 2015, the Company completed a public offering of 8,050,000 shares of its common stock generating net proceeds of $202.6 million after deducting underwriter discounts, commissions and offering expenses of approximately $6.7 million. The Company intends to use net proceeds to repay all of the outstanding borrowings under its revolving credit facility and for general corporate purposes, including the Company’s drilling and development program and other capital expenditures.

Three-stream reporting

Effective as of January 1, 2015, the Company revised the agreements with its natural gas processors in the Rocky Mountain region to report operated sales volumes on a three stream basis, which separately reports NGLs extracted from the natural gas stream and sold as a separate product. The NGL volumes identified by the Company’s gas purchasers are converted to an oil equivalent. The Company believes that this conversion will more accurately convey its production and sales volumes, will allow results to be more comparable with those of its peers and will conform more closely to general industry convention.

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NOTE 16—OIL AND GAS ACTIVITIES

The Company's oil and natural gas activities are entirely within the United States. Costs incurred in oil and natural gas producing activities are as follows:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Acquisition(1) | $ 228,616 | $ 13,797 | $ 58,843 |
| Development(2)(3) | 659,633 | 452,455 | 341,135 |
| Exploration | 5,345 | 2,590 | 4,821 |
| Total(4) | $ 893,594 | $ 468,842 | $ 404,799 |

(1) Acquisition costs for unproved properties for the years ended December 31, 2014, 2013 and 2012 were $202.7 million, $3.4 million and $57.0 million, respectively. Acquisition costs for proved properties for the years ended December 31, 2014, 2013 and 2012 were $25.9 million, $10.4 million and $1.8 million, respectively.
(2) Development costs include workover costs of $9.8 million, $6.0 million and $4.5 million charged to lease operating expense during the years ended December 31, 2014, 2013 and 2012, respectively.
(3) Development costs include gas plant capital expenditures of $0, $4.3 million and $16.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.
(4) Includes amounts relating to asset retirement obligations of $6.3 million, $2.8 million and $1.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The net changes in capitalized exploratory well costs are as follows:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Beginning balance at January 1 | $ — | $ — | $ 5,438 |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | — | — | 2,940 |
| Reclassifications to wells, facilities and equipment based on the determination of proved reserves | — | — | — |
| Capitalized exploratory well costs charged to expense | — | — | (8,378) |
| Ending balance at December 31 | $ — | $ — | $ — |

During the year ended December 31, 2014, the Company incurred drilling costs for one exploratory well of $1,043,000 and deemed it a dry hole by the end of 2014. During the year ended December 31, 2013, the Company incurred drilling costs for one exploratory well of $629,886 and deemed it a dry hole by the end of 2013. During the year ended December 31, 2012, the Company incurred $8,378,612 of dry hole expense.

NOTE 17—DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The proved reserve estimates at December 31, 2014 are internally generated with an audit performed by NSAI, our third party independent reserve engineers, whereas the December 31, 2013 proved reserve estimates were prepared by NSAI and 2012 proved reserve estimates were prepared by Cawley, Gillespie & Associates, Inc. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

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All of BCEI's oil, natural gas liquids, and natural gas reserves are attributable to properties within the United States. A summary of BCEI's changes in quantities of proved oil, natural gas liquids, and natural gas reserves for the years ended December 31, 2014, 2013 and 2012 are as follows:

| | Oil (MBbl)(1) | Natural Gas (MMcf) |
|---|---|---|
| Balance—December 31, 2011 | 28,216 | 92,982 |
| Extensions and discoveries(2) | 12,016 | 50,667 |
| Sales of minerals in place | (669) | — |
| Production | (2,529) | (5,475) |
| Purchases of minerals in place | — | — |
| Revisions to previous estimates(3) | (3,768) | (19,626) |
| Balance—December 31, 2012 | 33,266 | 118,548 |
| Extensions and discoveries(2) | 20,123 | 59,936 |
| Sales of minerals in place | — | — |
| Production | (4,257) | (9,976) |
| Purchases of minerals in place | 1,228 | 3,958 |
| Revisions to previous estimates(3) | (3,878) | (32,852) |
| Balance—December 31, 2013 | 46,482 | 139,614 |
| Extensions and discoveries(2) | 13,222 | 41,963 |
| Sales of minerals in place | (43) | (73) |
| Production | (6,018) | (14,114) |
| Purchases of minerals in place | 709 | 1,214 |
| Revisions to previous estimates(3) | 3,760 | 19,947 |
| Balance—December 31, 2014 | 58,112 | 188,551 |
| Proved developed reserves: | | |
| December 31, 2012 | 15,675 | 48,942 |
| December 31, 2013 | 22,273 | 59,250 |
| December 31, 2014 | 30,542 | 94,494 |
| Proved undeveloped reserves: | | |
| December 31, 2012 | 17,591 | 69,606 |
| December 31, 2013 | 24,209 | 80,364 |
| December 31, 2014 | 27,570 | 94,057 |

(1) Natural gas liquids reserves are classified with oil reserves.

(2) At December 31, 2014, horizontal development in the Wattenberg Field, Rocky Mountain region, resulted in additions in extensions and discoveries of 18,980 MBoe, which is 94% of our total additions of 20,216 MBoe. The remainder of the additions came from our Dorcheat Madedonia Field, Mid Continent region.

At December 31, 2013, horizontal development in the Wattenberg Field, Rocky Mountain region, resulted in additions in extensions and discoveries of 28,908 MBoe, which is 96% of our total additions of 30,112 MBoe. The remainder of the additions came from our Dorcheat Madedonia and McKamie Patton Fields, Mid Continent region.

At December 31, 2012, horizontal development in the Wattenberg Field, Rocky Mountain region, resulted in additions in extensions and discoveries of 17,380 MBoe, which is 85% of our total additions of 20,461 MBoe. The remainder of the additions were the result of vertical drilling during the year in the Wattenberg Field and proved developed non producing and proved undeveloped reserve additions in the Dorcheat Macedonia Field, Mid Continent region.

(3) As of December 31, 2014, we revised our proved reserves upward by 7,333 Mboe, excluding pricing revisions, due primarily to the addition of 49 new proved undeveloped locations on 80-acre spacing, directly offsetting economic proved producing wells drilled prior to 2014, 21 diagonal offsets to economic proved producing wells and 12 proved

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undeveloped locations greater than one offset to economic proved producing wells but within developed areas and surrounded by proved producing wells. As of December 31, 2014, approximately 70% of our horizontal development in the Wattenberg Field was in the Niobrara B formation. A total of 119 horizontal proved undeveloped locations were added to the proved reserves at December 31, 2014 to either extensions and discoveries or revisions to previous estimates. The positive engineering revision was offset by a small negative performance revision of approximately 540 MBoe. A small negative pricing revision of 248 MBoe resulted from a decrease in average commodity price from $96.91 per Bbl WTI and $3.67 per MMBtu HH for the year ended December 31, 2013 to $94.99 per Bbl WTI and $4.35 per MMBtu HH for the year ended December 31, 2014.

At December 31, 2013, we revised our proved reserves downward by 9,867 MBoe, excluding pricing revisions, due primarily to the change in focus from vertical to horizontal development in the Watterberg Field. This accounted for 69% of the downward revision and included the elimination of 45 net vertical locations from proved undeveloped, the elimination of all proved non producing reserves associated with vertical well refracs and recompletions, and lower performance from the vertical producers due to increased line pressure. The high line pressure also affected the horizontal reserves creating a negative revision of 1.8 MMBoe, or 18% of the total downward revision. We had a small positive pricing revision of 514 MBoe from an increase in commodity price from $94.71 per Bbl WTI and $2.76 per MMBtu HH for the year ended December 31, 2012 to $96.91 per Bbl WTI and $3.67 per MMBtu HH for the year ended December 31, 2013.

At December 31, 2012, we revised our proved reserves downward by 6,938 MBoe, excluding pricing revisions, due primarily to a combination of eliminating 50 locations from proved undeveloped reserves as a result of a change in focus from vertical to horizontal development and lower performance than expected from our vertical producers in our Wattenberg Field, Rocky Mountain region. A small negative pricing revision of 101 MBoe resulted from a decrease in commodity price from $96.19 per Bbl WTI and $4.12 per MMBtu HH for the year ended December 31, 2011 to $94.71 per Bbl WTI and $2.76 per MMBtu HH for the year ended December 31, 2012.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with accounting authoritative guidance. Future cash inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carry forwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of BCEI’s oil and natural gas properties.

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The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Future cash flows | $ 5,780,745 | $ 4,799,149 | $ 3,367,465 |
| Future production costs | (2,257,572) | (1,681,419) | (1,037,537) |
| Future development costs | (952,041) | (776,512) | (684,160) |
| Future income tax expense | (457,625) | (576,024) | (298,201) |
| Future net cash flows | 2,113,507 | 1,765,194 | 1,347,567 |
| 10% annual discount for estimated timing of cash flows | (1,006,131) | (839,911) | (664,126) |
| Standardized measure of discounted future net cash flows | $ 1,107,376 | $ 925,283 | $ 683,441 |

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at period end.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Beginning of period | $ 925,283 | $ 683,441 | $ 666,186 |
| Sale of oil and gas produced, net of production costs | (435,792) | (346,679) | (189,840) |
| Net changes in prices and production costs | (331,930) | 94,881 | (81,527) |
| Extensions, discoveries and improved recoveries | 492,144 | 571,384 | 310,595 |
| Development costs incurred | 116,958 | 67,063 | 161,527 |
| Changes in estimated development cost | (15,131) | 127,034 | (9,404) |
| Purchases of mineral in place | 30,919 | 5,442 | — |
| Sales of mineral in place | (1,173) | — | (14,909) |
| Revisions of previous quantity estimates | 122,169 | (212,034) | (156,867) |
| Net change in income taxes | 68,856 | (150,704) | (23,441) |
| Accretion of discount | 122,722 | 83,468 | 79,398 |
| Changes in production rates and other | 12,351 | 1,987 | (58,277) |
| End of period | $ 1,107,376 | $ 925,283 | $ 683,441 |

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2014, 2013 and 2012 were calculated using the twelve month arithmetic average of first day of the month price inclusive of adjustments for quality and location.

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Oil (per Bbl) | $ 84.28 | $ 92.03 | $ 91.04 |
| Gas (per Mcf) | $ 5.24 | $ 4.67 | $ 3.78 |

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NOTE 18—QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2014 and 2013:

| | Three Months Ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| | (in thousands, except per share data) | | | |
| 2014 | | | | |
| Oil and gas sales(2) | $ 127,395 | $ 151,682 | $ 156,371 | $ 123,185 |
| Operating profit(1)(2) | 58,432 | 63,284 | 59,579 | 25,708 |
| Net income (loss) | 13,531 | 1,158 | 48,782 | (43,188) |
| Basic net income (loss) per common share | $ 0.34 | $ 0.03 | $ 1.18 | $ (1.05) |
| Diluted net income (loss) per common share | $ 0.34 | $ 0.03 | $ 1.18 | $ (1.06) |
| 2013 | | | | |
| Oil and gas sales(2) | $ 78,307 | $ 84,517 | $ 125,973 | $ 133,063 |
| Operating profit(1)(2) | 39,001 | 36,750 | 68,179 | 62,780 |
| Net income | 11,256 | 14,715 | 17,781 | 25,432 |
| Basic net income per common share | $ 0.28 | $ 0.36 | $ 0.44 | $ 0.64 |
| Diluted net income per common share | $ 0.28 | $ 0.36 | $ 0.44 | $ 0.63 |

(1) Oil and gas sales less lease operating expense, severance and ad valorem taxes, depreciation, and depletion and amortization.

(2) Amounts reflect results for continuing operations and exclude results for discontinued operations related to non core properties in California sold or held for sale as of December 31, 2014 and 2013.

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

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2014. The term “disclosure controls and procedures,” as defined in Rules 13a 15(e) and 15d 15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive and principal financial officers and internal audit function, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2014, our principal executive officer and principal financial officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost benefit relationship of possible controls and procedures. To assist management, we have established an internal audit function to verify and monitor our internal controls and procedures. The Company's internal control system is supported by written policies and procedures, contains self-monitoring mechanisms and is audited by the internal audit function. Appropriate actions are taken by management to correct deficiencies as they are identified.

Management's Assessment of Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a 15(f). The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the 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 processes may deteriorate.

As of December 31, 2014, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control—Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2014, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

Hein & Associates LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10 K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2014, which is included in the consolidated financial statements in Item 8, Part II of this Annual Report on Form 10 K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in management's evaluation pursuant to Rules 13a 15(d) or 15d 15(d) of the Exchange Act during the year ended December 31, 2014 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Bonanza Creek Energy, Inc.

We have audited Bonanza Creek Energy, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Bonanza Creek Energy, Inc.'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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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 (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (b) 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 (c) provide reasonable assurance regarding prevention or timely detection of

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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, Bonanza Creek Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Bonanza Creek Energy, Inc. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014, and our report dated February 27, 2015 expressed an unqualified opinion.

/s/ Hein & Associates LLP

Denver, Colorado

February 27, 2015

Item 9B.  Other Information.

None.

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## PART III

### Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated by reference to Bonanza Creek Energy, Inc.'s Proxy Statement for its 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2014.

Our board of directors has adopted a Code of Business Conduct and Ethics applicable to all officers, directors and employees, which is available on our website (www.bonanzacrk.com) under "Corporate Governance" under the "For Investors" tab. We will provide a copy of this document to any person, without charge, upon request, by writing to us at Bonanza Creek Energy, Inc., Investor Relations, 410 17th Street, Suite 1400, Denver, Colorado 80202. We intend to satisfy the disclosure requirement under Item 406(c) of Regulation S K regarding an amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on our website at the address and the location specified above.

### Item 11. Executive Compensation.

The information required by this item is incorporated by reference to Bonanza Creek Energy, Inc.'s Proxy Statement for its 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2014.

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

The information required by this item is incorporated by reference to Bonanza Creek Energy, Inc.'s Proxy Statement for its 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2014.

### Item 13. Certain Relationships and Related Transaction and Director Independence.

The information required by this item is incorporated by reference to Bonanza Creek Energy, Inc.'s Proxy Statement for its 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2014.

### Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference to Bonanza Creek Energy, Inc.'s Proxy Statement for its 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2014.

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PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) The following documents are filed as a part of this Annual Report on Form 10 K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The information required by this Item is set forth on the exhibit index that follows the signature page to this Annual Report on Form 10 K.

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SIGNATURES

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

BONANZA CREEK ENERGY, INC.

By: /s/ Richard J. Carty

Richard J. Carty,
President and Chief Executive Officer
(principal executive officer)

February 27, 2015

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Richard J. Carty, William J. Cassidy, Christopher I. Humber and Wade E. Jaques and each of them severally, his true and lawful attorney or attorneys in fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys in fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys in fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

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

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| | | Interim President and Chief Executive Officer<br>(principal executive officer) |
| Date: February 27, 2015 | By: | /s/ Richard J. Carty |
| | | Richard J. Carty,<br>President, Chief Executive Officer, and Director<br>(principal executive officer) |
| Date: February 27, 2015 | By: | /s/ William J. Cassidy |
| | | William J. Cassidy,<br>Executive Vice President and Chief Financial Officer (principal financial officer) |
| Date: February 27, 2015 | By: | /s/ Wade E. Jaques |
| | | Wade E. Jaques,<br>Vice President and Chief Accounting Officer<br><br>(principal accounting officer) |
| Date: February 27, 2015 | By: | /s/ James A. Watt |
| | | James A. Watt,<br>Chairman of the Board |
| Date: February 27, 2015 | By: | /s/ Marvin M. Chronister |
| | | Marvin M. Chronister,<br>Director |
| Date: February 27, 2015 | By: | /s/ Kevin A. Neveu |
| | | Kevin A. Neveu,<br>Director |
| Date: February 27, 2015 | By: | /s/ Gregory P. Raih |
| | | Gregory P. Raih,<br>Director |
| Date: February 27, 2015 | By: | /s/ Jeff E. Wojahn |
| | | Jeff E. Wojahn,<br>Director |

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INDEX TO EXHIBITS

| Exhibit Number | Description |
|---|---|
| 3.1 | Second Amended and Restated Certificate of Incorporation of Bonanza Creek Energy, Inc., filed with the Secretary of State of the State of Delaware on December 16, 2011 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8 K filed on December 22, 2011) |
| 3.2 | Third Amended and Restated Bylaws of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8 K filed on August 1, 2013) |
| 4.1 | Form of Senior Debt Indenture (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S 3 filed on January 15, 2013) |
| 4.2 | Form of Subordinated Debt Indenture (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S 3 filed on January 15, 2013) |
| 4.3 | Registration Rights Agreement, dated April 9, 2013, among Bonanza Creek Energy, Inc., the guarantors named therein and Wells Fargo Securities, LLC, as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.2 of the Current Report on Form 8 K filed on April 11, 2013) |
| 4.4 | Indenture, dated as of April 9, 2013, among Bonanza Creek Energy, Inc., the guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Current Report on Form 8 K filed on April 11, 2013) |
| 4.5 | Indenture, dated July 18, 2014, among Bonanza Creek Energy, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on July 18, 2014) |
| 4.6 | First Supplemental Indenture, dated July 18, 2014, among Bonanza Creek Energy, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on July 18, 2014) |
| 4.7† | First Supplemental Indenture, dated January 27, 2015, among Rocky Mountain Infrastructure, LLC, Bonanza Creek Energy, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee |
| 4.8† | Second Supplemental Indenture, dated January 27, 2015, among Rocky Mountain Infrastructure, LLC, Bonanza Creek Energy, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee |
| 4.9 | Registration Rights Agreement by and between DJ Resources, LLC and Bonanza Creek Energy, Inc. dated July 8, 2014 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on July 11, 2014) |
| 10.1 | Credit Agreement, dated as of March 29, 2011, among Bonanza Creek Energy, Inc., BNP Paribas, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S 1 filed on June 7, 2011) |
| 10.2 | Amendment No. 1, dated as of April 29, 2011, to the Credit Agreement, among Bonanza Creek Energy, Inc., BNP Paribas, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S 1 filed on June 7, 2011) |
| 10.3 | Amendment No. 2 & Agreement, dated as of September 15, 2011, to the Credit Agreement, among Bonanza Creek Energy, Inc., BNP Paribas, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.14 to the Registration Statement on Form S 1/A filed on November 4, 2011) |
| 10.4 | Resignation, Consent and Appointment Agreement and Amendment Agreement, dated of April 6, 2012, by and among BNP Paribas, in its capacity as Administrative Agent and Issuing Lender, and the other parties thereto (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10 Q filed on May 11, 2012) |
| 10.5 | |

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| | Amendment No. 3 & Agreement, dated as of May 8, 2012, to the Credit Agreement among Bonanza Creek Energy, Inc., KeyBank National Association, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10 Q filed on May 11, 2012) |
| 10.6 | Amendment No. 4, dated as of July 31, 2012 to the Credit Agreement among Bonanza Creek Energy, Inc., Key Bank National Association, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10 Q filed on August 13, 2012) |

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| Exhibit Number | Description |
|---|---|
| 10.7 | Amendment No. 5, dated as of October 30, 2012, to the Credit Agreement among Bonanza Creek Energy, Inc., KeyBank National Association, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10 Q filed on November 9, 2012) |
| 10.8 | Amendment No. 6, dated as of March 29, 2013, to the Credit Agreement among Bonanza Creek Energy, Inc., KeyBank National Association, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10 Q filed on May 10, 2013) |
| 10.9 | Amendment No. 7, dated as of May 16, 2013 to the Credit Agreement among Bonanza Creek Energy, Inc., Key Bank National Association, as Administrative Agent, and the lenders party thereto (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10 Q filed on August 9, 2013) |
| 10.10 | Amendment No. 8, dated as of November 6, 2013, to the Credit Agreement, among Bonanza Creek Energy, Inc., the Guarantors, KeyBank National Association, as Administrative Agent and as Issuing Lender, and the lenders party thereto (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8 K filed on November 8, 2013) |
| 10.11 | Amendment No. 9 and Agreement, dated as of May 14, 2014, to the Credit Agreement, among Bonanza Creek Energy, Inc., the Guarantors, KeyBank National Association, as Administrative Agent and as Issuing Lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8 K filed on May 20, 2014) |
| 10.12 | Amendment No. 10 and Agreement, dated as of September 30, 2014, to the Credit Agreement, among Bonanza Creek Energy, Inc., the Guarantors, KeyBank National Association, as Administrative Agent and as Issuing Lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8 K filed on October 3, 2014) |
| 10.13 | Registration Rights Agreement, among Bonanza Creek Energy, Inc., Project Black Bear LP, Her Majesty the Queen in Right of Alberta, in her own capacity and as a trustee/nominee for certain designated entities and certain other stockholders of the Registrant (incorporated by reference to Exhibit 10.3 to the Registration Statement on Form S 1/A filed on July 25, 2011) |
| 10.14* | Form of Indemnity Agreement between Bonanza Creek Energy, Inc. and each of its directors and executive officers (incorporated by reference to Exhibit 10.4 to the Registration Statement on Form S 1/A filed on July 25, 2011) |
| 10.15* | Bonanza Creek Energy, Inc. 2011 Long Term Incentive Plan (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S 1/A filed on November 4, 2011) |
| 10.16* | Form of Restricted Stock Agreement (Employee) under the 2011 Bonanza Creek Energy, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10 Q filed on August 13, 2012) |
| 10.17* | Form of Restricted Stock Agreement (Director) under the 2011 Bonanza Creek Energy, Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10 Q filed on August 13, 2012) |
| 10.18* | Form of Performance Share Agreement for 2013 grants (incorporated by reference to Exhibit 10.3 of the Current Report on Form 8 K filed on March 29, 2013) |
| 10.19* | Form of Performance Share Agreement for 2014 grants (incorporated by reference to Exhibit 10.2 of the Quarterly Report on Form 10-Q filed on May 9, 2014) |
| 10.20* | Employment Letter Agreement effective March 21, 2014 between Bonanza Creek Energy, Inc. and Wade E. Jaques (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8 K filed on March 24, 2014) |
| 10.21* | Employment Letter Agreement dated November 11, 2014, between Bonanza Creek Energy, Inc. and Richard J. Carty (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8 K filed on November 14, 2014) |
| 10.22* | Performance Share Agreement dated November 11, 2014, between Bonanza Creek Energy, Inc. and Richard J. Carty (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on November 14, |

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| | 2014) |
| 10.23* | Restricted Stock Agreement dated November 10, 2014, between Bonanza Creek Energy, Inc. and Marvin M. Chronister (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed on November 14, 2014) |

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| Exhibit Number | Description |
|---|---|
| 10.24* | Severance Agreement effective January 31, 2014 between Bonanza Creek Energy, Inc. and Michael R. Starzer (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed on May 9, 2014) |
| 10.25* | Employment Letter Agreement effective April 29, 2013 between Bonanza Creek Energy, Inc. and Christopher I. Humber (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8 K filed on May 3, 2013) |
| 10.26* | Employment Letter Agreement, dated August 6, 2013, between Bonanza Creek Energy, Inc. and William J. Cassidy (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8 K filed on August 13, 2013) |
| 10.27* | Employment Letter Agreement, dated August 7, 2013, between Bonanza Creek Energy, Inc. and Anthony G. Buchanon (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8 K filed on August 13, 2013) |
| 10.28* | Form of Employment Letter Agreement (incorporated by reference to Exhibit 10.2 of the Current Report on Form 8 K filed on March 29, 2013) |
| 10.29* | Bonanza Creek Energy, Inc. Amended and Restated Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.3 of the Current Report on Form 8 K filed on November 14, 2014) |
| 10.30 | Purchase Agreement, dated April 4, 2013, among Bonanza Creek Energy, Inc., the subsidiary guarantors named therein and Wells Fargo Securities, LLC, as representative of the initial purchasers named therein (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8 K filed on April 5, 2013) |
| 10.31 | Underwriting Agreement, dated November 12, 2013, among Bonanza Creek Energy, Inc., the subsidiary guarantors named therein and Wells Fargo Securities, LLC, as representative of the underwriters named therein (incorporated by reference to Exhibit 1.1 of the Current Report on Form 8 K filed on November 15, 2013) |
| 10.32 | Underwriting Agreement, dated July 15, 2014, among Bonanza Creek Energy, Inc., the subsidiary guarantors named therein and RBC Capital Markets, LLC, as representative of the underwriters named therein (incorporated by reference to Exhibit 1.1 of the Current Report on Form 8-K filed on July 18, 2014) |
| 10.33 | Underwriting Agreement, dated February 3, 2015, among Bonanza Creek Energy, Inc. and Credit Suisse Securities (USA) LLC, as representative of the underwriters named therein (incorporated by reference to Exhibit 1.1 of the Current Report on Form 8-K filed on February 6, 2015) |
| 10.34 | Purchase and Sale Agreement by and between DJ Resources, LLC, Bonanza Creek Energy Operating Company, LLC and Bonanza Creek Energy, Inc. dated May 21, 2014 (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed on May 23, 2014) |
| 21.1† | List of subsidiaries |
| 23.1† | Consent of Hein & Associates LLP |
| 23.2† | Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc. |
| 23.3† | Consent of Independent Petroleum Engineers, Cawley, Gillespie & Associates, Inc. |
| 31.1† | Certification of the Chief Executive Officer pursuant to Rule 13a 14(a) |
| 31.2† | Certification of the Chief Financial Officer pursuant to Rule 13a 14(a) |
| 32.1† | Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (furnished herewith) |
| 32.2† | Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (furnished herewith) |
| 99.1† | Report of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc. for reserves as of December 31, 2014 |
| 101† | The following material from the Bonanza Creek Energy, Inc. Annual Report on Form 10 K for the year ended December 31, 2014 (and related periods), formatted in XBRL (Extensible Business Reporting Language) include (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations and Comprehensive Income, (iii) the Condensed Consolidated Statements of Stockholders' Equity, |

(iv) the Condensed Consolidated Statements of Cash Flows, and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text

*Management Contract or Compensatory Plan or Arrangement

†Filed or furnished herewith