Bonanza Creek Energy, Inc.
Form 10-K
February 28, 2014

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UNITED STATES
SECURITIES AND COMMISSION

Washington, D.C. 20549

Form 10-K

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013

OR

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

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 o No ý

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 ý No o

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 ý No o

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. ý

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 ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates on June 28, 2013, based upon the closing price of $35.46 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $847,821,792. Excludes approximately 16,377,774 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, 2014: 40,267,540

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2014 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, are incorporated by reference into Part III of this report for the year ended December 31, 2013.

BONANZA CREEK ENERGY, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2013

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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 to identify 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 production for 2014;
- 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 the most prospective area of the Niobrara formation and the Dorcheat Macedonia Field being a primary focus in the Mid-Continent region;
- compliance with debt covenants;
- ability to satisfy obligations related to ongoing operations;
- compliance with government regulations;
- adequacy of gathering systems and impact from the lack of available gathering systems and processing facilities in certain areas;
- natural gas, oil and NGL 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;
- 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;

intentions with respect to acquisitions and divestitures;

intentions with respect to working interest percentages;

management and technical team;

outcomes and effects of litigation, claims and disputes;

our business strategy;

our ability to replace oil and natural gas reserves;

impact of recently issued accounting pronouncements;

our financial position;

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- our cash flow and liquidity; 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;
- declines or volatility in the prices we receive for our oil, liquids and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- the continuing global economic slowdown that has and may continue to adversely affect consumption of oil and natural gas by businesses and consumers;
- 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 production 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;

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;

ability to maintain effective internal controls;

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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

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 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 volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

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"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.

"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.

"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.

"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

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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.

"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 international 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.

"NYMEX" The New York Mercantile Exchange.

"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 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.

"*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.

"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.

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"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 (i) when deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates; (ii) possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project; (iii) possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves; (iv) the proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects; (v) possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower that the proved area if these areas are in communication with the proved reservoir; (vi) where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

"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. (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates; (ii) probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved if these areas are in communication with the proved reservoir; (iii) probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"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

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wells and related equipment and facilities; (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.

"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

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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.

"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 EUR recovery 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.

"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.

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"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).

"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."

"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.

"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 subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under *Glossary of Oil and 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. 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. We operate approximately 99% of our proved reserves with an average working interest of approximately 89% 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, expecting to invest approximately 85% of our 2014 capital budget in this project. The remaining 15% of our 2014 budget is allocated primarily to the vertical development of the Dorcheat Macedonia and McKamie Patton Fields in southern Arkansas, targeting oil-rich Cotton Valley sands. We believe the location, size and concentration of our acreage in our core project areas provide an opportunity to significantly increase production, lower costs and further delineate the Company's resource potential. In 2013, we successfully drilled 134 and completed 121 productive operated wells and participated in drilling 12 and completing 4 productive non-operated wells. We had 17 operated wells in progress as of December 31, 2013. The resulting production rates achieved by this program increased sales volumes by 72% over the previous year to 16,219 Boe/d of which 72% was crude oil and natural gas liquids ("NGL"). The Rocky Mountain region contributed 66% and the Mid-Continent region contributed 34% to total production. Our average net daily production rate during December 2013 was 19,649 Boe/d, a 58% increase over December 2012.

In the second quarter 2012, we began the divestiture process of our non-core properties in California. 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. During 2012, we sold the majority of these properties for approximately $9.3 million in aggregate, with one property remaining to be sold as of December 31, 2013.

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Netherland, Sewell & Associates, Inc., our independent reserve engineers, estimated our net proved reserves as of December 31, 2013, to be as follows:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed				
Rocky Mountain	13,660	38,017		19,996
Mid-Continent	6,982	21,233	1,619	12,140
California	12			12
	20,654	59,250	1,619	32,148
Undeveloped				
Rocky Mountain	18,461	63,229		28,999
Mid-Continent	4,431	17,135	1,317	8,604
California				
	22,892	80,364	1,317	37,603
Total Proved	43,546	139,614	2,936	69,751

	Estimated Proved Reserves at December 31, 2013(1)				Production for the Year Ended December 31, 2013			
	Total Proved (MBoe)	% of Total	% Proved Developed	PV-10 ($ in MM)(2)	Average Net Daily Production (Boe/d)	% of Total	Projected 2014 Capital Expenditures ($ in millions)	Net Proved Undeveloped Drilling Locations as of December 31, 2013
Rocky Mountain	48,995	70%	41%	$ 908.9	10,618	66%	$ 500 - $540	161.3
Mid-Continent	20,744	30%	59%	318.1	5,554	34%	75 - 85	93.2
California	12	0%	100%	0.2	47	0%	0	0
Total	69,751	100%	46%	$ 1,227.2	16,219	100%	$ 575 - $625	254.5

(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 $96.91 per Bbl WTI and $3.67 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $4.88 per Bbl of crude oil and an increase of $1.00 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

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differs from Standarized 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.

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 relative to our cost of capital, and increase our production, proved reserves and cash flow. We intend to accomplish this by focusing on the following key strategies:

Increase Production from Wattenberg Horizontal Opportunities and Develop Additional Resource Potential in Both of our Core Areas. We intend to continue to develop the Niobrara and Codell formations utilizing horizontal drilling. While we are focused on the Niobrara B bench, primarily using 4,000 foot laterals, we have begun, and plan to continue, to develop the Niobrara C bench and Codell formation as well as to test extended reach lateral drilling in the Wattenberg Field and down-spacing concepts 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.

Pursue Ongoing Corporate Growth. We intend to pursue bolt-on acquisitions in the Wattenberg Field and in southern Arkansas where we can take advantage of our core operational and engineering competencies. In addition, we will evaluate acquisitions of other opportunities where we believe the application of our core competencies will enhance shareholder value.

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 oil production.

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, 2013, we have accumulated approximately 35,500 net acres in the Wattenberg Field prospective for the Niobrara formation, of which, approximately 18,000 net acres have been successfully tested to have prospective for the Codell formation. We will continue to test our remaining Wattenberg Field acreage to prove out 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 73% of current production, yielding strong economic returns at current commodity prices. We believe our acreage position represents a large inventory of high value, ready-to-drill potential locations with significant upside potential and that the consistently

positive results in this play by us and other operators validate our investment and the continued development of the area. We believe adequate gathering systems and takeaway capacity are in place in this area, enabling a short time period 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 which allows 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.

High Degree of Operational Control. We operate approximately 99% of our proved reserves with an average working interest of approximately 89% 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 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. Our senior technical team averages more than 30 years of industry experience, including experience in multiple North American resource plays and basins. We believe our management and technical team is one of our principal competitive strengths due to its proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, this team possesses substantial expertise in horizontal drilling techniques and fracture stimulation.

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, 2013 was approximately $595 million, which was comprised of $414 million of availability under our credit facility, if we elect to take advantage of our entire borrowing base, and approximately $181 million of cash on hand. We also employ a disciplined approach to management of leverage and govern our organic capital spending programs.

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.

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, 2013, our Wattenberg position consisted of approximately 40,000 gross (35,500 net) acres. During 2013, we had a net increase of approximately 4,500 net acres in the Wattenberg Field, which includes an increase in net acreage of approximately 5,250 acres through acquisitions and leasing in our core area and a reduction of approximately 750 net acres due to expiration of non-core lands, adjustments in ownership due to further title information and other adjustments including strategic partnerships and pooling arrangements. We own 3-D seismic surveys covering substantially all of our

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acreage in the Wattenberg Field, which helps provide efficient and targeted horizontal drilling operations.

The Wattenberg Field is now primarily developed for the Niobrara and Codell formations using horizontal drilling and multi-stage fracture stimulation techniques. We believe our acreage position has been fully delineated for the Niobrara B bench and expect this horizon to be a primary source of future production growth. In addition, our testing in the Niobrara C bench and Codell formation has been successful to date and supports future delineation and development drilling.

Our estimated proved reserves at December 31, 2013 in the Wattenberg Field were 48,725 MBoe. As of December 31, 2013, we had a total of 313 gross producing wells, of which 124 gross were horizontal wells, and our average daily production during 2013 was approximately 10,495 Boe/d, of which 91% came from horizontal wells. Our average daily production for the month of December 2013 was 13,619 Boe/d. Our working interest for all producing wells averages approximately 91% and our net revenue interest is approximately 82%

We continue to expand our proved reserves in this area by drilling non-proved horizontal locations. During 2013, we drilled 87 horizontal wells and successfully completed 73. In the Niobrara B bench, we drilled 69 and successfully completed 62 standard length (4,000 foot lateral) horizontal wells and two extended reach horizontal wells with average lateral length of 9,240 feet during 2013. Since we began our horizontal Niobrara B bench drilling program in 2011, through December 31, 2013, we have drilled and successfully completed 98 wells of which 92 are on 80-acre spacing and 6 are on 40-acre spacing. We believe the results demonstrated by our wells spaced at 40 acres warrant continued development of the Niobrara B bench at that spacing density. In addition, we believe the results demonstrated by our extended reach laterals warrant continued testing of lateral lengths of greater than 4,000 feet. In the Niobrara C bench and Codell formation, we drilled 10 and 6 standard length (4,000 foot lateral) horizontal wells, respectively, and successfully completed 5 and 4 standard length (4,000 foot lateral) horizontal wells during 2013. The drilling results demonstrated in the Niobrara C bench and Codell formation were in-line with expectations and provide the basis for our accelerated development plan during 2014.

We estimate our capital expenditures in the Wattenberg Field for 2014 will be $493 million to $533 million, which includes drilling a projected 87 horizontal wells in the Niobrara B bench, 16 horizontal wells in the Niobrara C bench, one horizontal well in the Niobrara A bench and 17 horizontal wells in the Codell sandstone. This drilling program includes approximately 23 proved locations and 98 non-proved locations and approximately $28 million for non-operated horizontal drilling.

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 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, 2013 were approximately 270 MBoe, 100% of which were crude oil. Our average net production during 2013 was approximately 123 Boe/d. None of our CO_2 production is currently reflected in our reserve reports.

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. We have budgeted approximately $7 million during 2014 to drill two exploration wells in 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, 2013, our estimated proved reserves in this region were 20,744 MBoe, 69% of which were oil and natural gas liquids and 59% of which were proved developed. We currently operate 237 producing vertical wells and, as of December 31, 2013, have an identified drilling inventory of approximately 112 gross (93 net) PUD drilling locations on our acreage. During 2013, we drilled 47 wells and successfully completed 48 wells in the Dorcheat Macedonia and McKamie Patton Fields. We achieved an average production rate for 2013 of 5,554 Boe/d, of which 70% was from crude oil and liquids, and an average production rate for December 2013 of 5,889 Boe/d. Productive reservoirs range in depth from 4,500 to 9,000 feet in depth. Those reservoirs include the Smackover and the Pettet, but our primary development target is the Cotton Valley.

Dorcheat Macedonia. In the Dorcheat Macedonia Field, we average an approximate 84% working interest and an approximate 70% net revenue interest on all producing wells, and the majority of our acreage is held by unitization, production, or drilling operations. We have approximately 190 gross producing wells and our average net daily production during 2013 was approximately 5,116 Boe/d. During the month of December 2013, it was approximately 5,541 Boe/d. Our proved reserves in this field are approximately 19,377 MBoe. Prior to 2013, the development plan for the Dorcheat Macedonia Field was based on a maximum well density equal to 10-acre spacing. Late in 2012, we initiated the first of three pilot tests which increased well density to 5-acre spacing. Results from these pilots are encouraging and we plan to allocate 19% of our 2014 capital budget in the Mid-Continent region to this down-spacing project.

As of December 31, 2013, we have identified approximately 110 gross (91 net) PUD drilling locations on our acreage in this area. During 2013, we drilled 44 and successfully completed 45 vertical Cotton Valley wells in Dorcheat Macedonia. We have budgeted capital expenditures for 2014 of approximately $75 million to $85 million for the development of this field. In 2014, we expect to drill 34 PUD locations on 10-acre spacing with a complete cost per well of approximately $1.8 million, approximately $1.7 million of which will be for initial drilling and completion with the remaining $100,000 attributed to the first recompletion generally executed within six months of first production. In addition, we expect to drill 10 wells on 5-acre spacing and perform 112 recompletions on existing wells.

Other Mid-Continent. We own additional interests in our Mid-Continent region near the Dorcheat Macedonia Field. These include interests in the McKamie Patton, Atlanta and Beech Creek Fields. As of December 31, 2013, our estimated aggregate proved reserves in these fields were approximately 1,367 MBoe, and average net daily production during 2013 was approximately 438 Boe/d. During 2013, we drilled 3 vertical Cotton Valley wells in the McKamie-Patton Field. In 2014, we expect to continue development at McKamie-Patton with 4 vertical Cotton Valley wells.

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.

Reserves

Estimated Proved Reserves

Unless otherwise specifically identified, the summary data with respect to our estimated proved reserves presented below has been prepared by our independent reserve engineering firm in accordance with rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to

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companies involved in oil and natural gas producing activities. Our proved reserve estimates do not include probable or possible reserves which may exist, categories which the new SEC rules now permit us to disclose in public reports. Our estimated proved reserves for the years ended December 31, 2013, 2012, and 2011 and for future periods are 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 and undeveloped locations 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. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the SEC, since the beginning of the last fiscal year.

The table below summarizes our estimated proved reserves at December 31, 2013, 2012, and 2011 for each of the areas in which we operate. The proved reserve estimates at December 31, 2013 presented in the table below are based on reports prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineers, whereas the December 31, 2012 and 2011 estimated proved reserved were prepared by Cawley, Gillespie & Associates, Inc. In preparing these reports, Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc. evaluated 100% of our properties at December 31, 2013, 2012, and 2011. 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	**2013**	**2012**	**2011**
		(MMBoe)	
Rocky Mountain	**49.1**	**32.4**	**21.4**
Wattenberg	48.8	31.9	20.8
North Park	0.3	0.5	0.6
Mid-Continent	**20.7**	**20.6**	**21.6**
Dorcheat Macedonia	19.4	19.0	19.9
McKamie Patton	1.3	1.6	1.6
Other	0.0	0.0	0.1
California	**0.0**	**0.0**	**0.7**
Total	**69.8**	**53.0**	**43.7**

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The following table sets forth more information regarding our estimated proved reserves at December 31, 2013, 2012, and 2011:

	At December 31,		
	2013	2012	2011
Reserve Data(1):			
Estimated proved reserves:			
Oil (MMBbls)	43.6	30.2	24.6
Natural gas (Bcf)	139.6	118.5	93.0
Natural gas liquids (MMBbls)	2.9	3.1	3.6
Total estimated proved reserves (MMBoe)(2)	69.8	53.0	43.7
Percent oil and liquids	67%	63%	65%
Estimated proved developed reserves:			
Oil (MMBbls)	20.7	14.3	10.6
Natural gas (Bcf)	59.2	48.9	31.3
Natural gas liquids (MMBbls)	1.6	1.3	1.2
Total estimated proved developed reserves (MMBoe)(2)	32.2	23.8	17.0
Percent oil and liquids	69%	66%	69%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	22.9	15.8	14.0
Natural gas (Bcf)	80.4	69.6	61.7
Natural gas liquids (MMBbls)	1.3	1.8	2.4
Total estimated proved undeveloped reserves (MMBoe)(2)	37.6	29.2	26.7
Percent oil and liquids	64%	60%	61%

(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 $96.91 per Bbl WTI and $3.67 per MMBtu HH, $94.71 per Bbl WTI and $2.76 per MMBtu HH, $96.19 per Bbl WTI and $4.12 per MMBtu HH for the years ended December 31, 2013, 2012 and 2011 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. All proved undeveloped locations in our December 31, 2013 reserves report are scheduled to be drilled within five years from their initial proved booking date. The technologies used to establish our proved reserves are a combination of geologic mapping, electric logs, seismic data and production data.

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 is comprised of 28.9 MMBoe of additions in extensions and discoveries offset by 3.8 MMBoe in production 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

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(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 production and negative revisions of 6.1 MMBoe. The negative revision results 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 is 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.

Estimated proved reserves at December 31, 2011 were 43.7 MMBoe, a 33% increase from estimated proved reserves of 32.9 MMBoe at December 31, 2010. All proved undeveloped locations included in our December 31, 2011 reserves report are scheduled to be drilled within five years from their initial proved booking date. The increase was primarily due to extensions and discoveries associated with the Rocky Mountain region and was comprised of 168 new proved undeveloped locations and 54 unproved locations that were drilled during 2011 and moved directly to proved reserves. Another component of the increase was our commodity price assumption for oil which increased $16.76 per Bbl WTI to $96.19 per Bbl WTI for the year ended December 31, 2011 from $79.43 per Bbl WTI for the year ended December 31, 2010.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, 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 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.

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The following table provides a reconciliation of PV-10 to the Standardized Measure at December 31, 2013, 2012 and 2011:

	December 31,		
	2013	2012	2011
	(in millions)		
PV-10	$ 1,227.2	$ 834.7	$ 794.0
Present value of future income taxes discounted at 10%	(301.9)	(151.3)	(127.8)
Standardized Measure	$ 925.3	$ 683.4	$ 666.2

Proved Undeveloped Reserves

	Net Reserves, MBoe At December 31,		
	2013	2012	2011
Beginning of year	29,192	26,652	21,334
Converted to proved developed	(3,047)	(5,166)	(4,184)
Additions from capital program	16,535	13,913	10,190
Acquisitions (sales)	1,779	(430)	
Revisions (pricing and engineering)	(6,856)	(5,777)	(688)
End of year	37,603	29,192	26,652

At December 31, 2013, our proved undeveloped reserves were 37,603 MBoe, all of which are scheduled to be drilled within five years of their initial disclosure. At December 31, 2012, our proved undeveloped reserves were 29,192 MBoe. 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. In 2014, our drilling plans include proved undeveloped drilling estimated to convert over 20% of our proved undeveloped reserves into proved developed reserves. Executing 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 results 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. At December 31, 2011, our proved undeveloped reserves were 26,652 MBoe. 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.

At December 31, 2011, our proved undeveloped reserves were 26,652 MBoe, all of which were scheduled to be drilled within five years of their initial disclosure. At December 31, 2010, our proved undeveloped reserves were 21,334 MBoe. During 2011, 4,184 MBoe or 19.6% of our proved

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undeveloped reserves were converted into proved developed reserves requiring $93.9 million of capital. The majority of the reserves converted to proved developed during 2011, 3,176 MBoe or 76%, resulted from our capital program in the Mid-Continent region. Executing the 2011 capital program in both the Rocky Mountain and Mid-Continent regions resulted in the addition of 10,190 MBoe in proved undeveloped reserves.

Internal controls over reserves estimation process

We maintain an internal staff of petroleum engineers and geoscience professionals who ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers for their reserves estimation process. The technical person primarily responsible for overseeing the reserves process within the Company is 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 25 years. She has managed the technical reserve process at a company level for over ten years.

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 year ended December 31, 2013 shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. ("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 preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Dan Paul Smith and Mr. John Hattner. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 1980. Mr. Smith is a Licensed Professional Engineer in the State of Texas (License No. 49093) and has over 30 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner has been practicing consulting petroleum geology at NSAI since 1991. Mr. Hattner is a Licensed Professional Geoscientist in the State of Texas, Geology, (License No. 559) and has over 30 years of practical experience in petroleum geosciences, with over 20 years experience in the estimation and evaluation of reserves. 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 years ended December 31, 2011 and 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

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1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 24 years of practical experience in petroleum engineering, with over 22 years' 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.

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. Demand for oil and natural gas in the United States has increased dramatically over the last ten years. Beginning in 2010 there was a steady decline in natural gas prices but prices stabilized in the twelve month period ended December 31, 2013. The decline was caused by a global economic downturn and increased inventory of natural gas. Oil prices have steadily increased since 2010 and continued to do so during the twelve month period ended December 31, 2013. The increase was caused by increased demand coupled with unexpected global production outages.

Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, 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.

The following table sets forth information regarding oil and natural gas production, realized prices, and production costs for the periods indicated. For additional information on price calculations, please

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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,		
	2013(1)	**2012(1)**	**2011**
Oil:			
Total Production (MBbls)	3,887.2	2,191.0	887.4
Wattenberg Field	2,775.6	1,190.8	400.8
Dorcheat Macedonia Field	925.2	789.5	359.8
Average sales price (per Bbl), including derivatives(2)	$ 88.82	$ 88.40	$ 85.51
Average sales price (per Bbl), excluding derivatives(2)	$ 91.84	$ 89.08	$ 89.67
Natural Gas:			
Total Production (MMcf)	9,975.9	5,473.2	2,773.1
Wattenberg Field	6,269.1	2,485.6	1,072.2
Dorcheat Macedonia Field	3,598.3	2,973.8	1,642.2
Average sales price (per Mcf), including derivatives(2)	$ 4.70	$ 3.76	$ 5.09
Average sales price (per Mcf), excluding derivatives(2)	$ 4.66	$ 3.62	$ 4.85
Natural Gas Liquids:			
Total Production (MBbls)	352.8	284.7	183.8
Wattenberg Field	10.2		
Dorcheat Macedonia Field	342.6	284.7	183.8
Average sales price (per Bbl), including derivatives	$ 51.74	$ 55.54	$ 67.23
Average sales price (per Bbl), excluding derivatives	$ 51.74	$ 55.54	$ 67.23
Oil Equivalents:			
Total Production (MBoe)	5,902.7	3,387.9	1,533.4
Wattenberg Field	3,830.7	1,605.0	579.5
Dorcheat Macedonia Field	1,867.5	1,569.8	817.3
Average daily production (Boe/d)	16,171.8	9,257	4,201.1
Wattenberg Field	10,495.0	4,385.4	1,587.7
Dorcheat Macedonia Field	5116.4	4,289.1	2,239.2
Average Production Costs (per Boe)	$ 8.09	$ 9.06	$ 13.37

(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.

(2) Excludes ad valorem and severance taxes.

Principal Customers

Three of our customers, Plains Marketing LP, Lion Oil Trading & Transportation, Inc., and High Sierra Crude Oil & Marketing comprised 37%, 23%, and 15%, respectively, of our total revenue for the year ended December 31, 2013. No other single non-affiliated customer accounted for 10% or more of crude oil and natural gas sales in 2013. 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 do not have any material delivery commitments.

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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, 2013.

	Oil		Natural Gas(1)		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	425	396.9			425	396.9	407	391.4
Mid-Continent	237	197.3			237	197.3	236	197.3
California	22	22.0			22	22.0	22	22.0
Total	684	616.2			684	616.2	665	610.7

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

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, 2013 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	37,998	36,208	23,168	16,057	61,166	52,265	$ 908,857
Wattenberg Field	30,184	28,394	9,374	7,062	39,558	35,456	902,625
Other Rocky Mountain	7,814	7,814	13,794	8,995	21,608	16,809	6,232
Mid-Continent	5,397	4,130	6,846	5,128	12,243	9,258	318,139
Dorcheat Macedonia Field	4,117	2,894	2,129	1,304	6,246	4,198	280,571
Other Mid-Continent	1,280	1,236	4,717	3,824	5,997	5,060	37,568
California	480	480			480	480	229
Total	43,875	40,818	30,014	21,185	73,889	62,003	$ 1,227,225

Undeveloped acreage

The following table sets forth the number of net undeveloped acres as of December 31, 2013 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 2014		Expiring 2015		Expiring 2016	
Gross	Net	Gross	Net	Gross	Net

Rocky Mountain	320	574	2,631	2,674	2,561	1,233
Mid-Continent			137	122	1,099	696
California						
Total	320	574	2,768	2,796	3,660	1,929

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Drilling Activity

The following table describes the exploratory and development wells we drilled and completed during the years ended December 31, 2013, 2012, and 2011.

	For the Years Ended December 31,					
	2013(1)		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive Wells					53	52.9
Dry Wells	1	1	1	1		
Total Exploratory	1	1	1	1	53	52.9
Development						
Productive Wells	117	102.7	149	140.9	53	48.9
Dry Wells						
Total Development	117	102.7	149	140.9	53	48.9
Total	118	103.7	150	141.9	106	101.8

The following table describes the present drilling activities as of December 31, 2013.

	As of December 31, 2013	
	Gross	Net
Exploratory		
Rocky Mountain		
Mid-Continent		
California		
Total Exploratory		
Development		
Rocky Mountain	15	15
Mid-Continent	2	2
California		
Total Development	17	17
Total	17	17

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Capital Expenditure Budget

Our anticipated 2014 capital budget is in a range of $575 million to $625 million which, at the midpoint of the range, represents an increase of 27% over capital spending during 2013 of $472 million. We plan to spend approximately $500 million to $540 million or 87% of our total 2014 budget in the Rocky Mountain region. Projected drilling, completion and infrastructure expenditures in the Wattenberg Field will account for approximately 99% of the capital allocated to the Rocky Mountain region. In the Mid-Continent region, we plan to spend approximately $75 million to $85 million during 2014. In total, we plan to spend approximately $545 million on operated drilling and completion activities with the remainder allocated to non-operated drilling and completion activities, field infrastructure and maintenance operations. 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, 2013, 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	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability)
Oil							
1Q 2014	Swap	3,133	$ 96.97				$ (403,499)
2Q 2014	Swap	4,126	$ 96.20				(288,370)
3Q 2014	Swap	3,870	$ 93.04				(518,444)
4Q 2014	Swap	3,870	$ 93.04				205,179
1Q 2014	Collar	5,617			$ 86.33	$ 97.09	(1,338,410)
2Q 2014	Collar	4,846			$ 86.55	$ 96.72	(1,252,787)
3Q 2014	Collar	4,326			$ 86.16	$ 96.57	(615,971)
4Q 2014	Collar	4,326			$ 86.16	$ 96.57	(68,724)
2014	3-Way Collar	1,000		$ 60.00	$ 85.00	$ 99.50	(303,314)
2015	3-Way Collar	4,500		$ 66.67	$ 83.33	$ 94.12	(782,385)
							$ (5,366,725)
Gas							
2014	3-Way Collar	15,000		$ 3.50	$ 4.00	$ 4.75	$ 122,173
2015	3-Way Collar	15,000		$ 3.50	$ 4.00	$ 4.75	(127,895)
							$ (5,722)
Total							$ (5,372,447)

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As of the date of filing 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	Average Floor Price	Average Ceiling Price
Oil						
1Q 2014	Swap	3,133	$ 96.97			
2Q 2014	Swap	4,126	$ 96.20			
3Q 2014	Swap	3,870	$ 93.04			
4Q 2014	Swap	3,870	$ 93.04			
1Q 2014	Collar	5,617			$ 86.33	$ 97.09
2Q 2014	Collar	4,846			$ 86.55	$ 96.72
3Q 2014	Collar	4,326			$ 86.16	$ 96.57
4Q 2014	Collar	4,326			$ 86.16	$ 96.57
1Q 2014	3-Way collar	1,000		$ 60.00	$ 85.00	$ 99.50
2Q - 4Q 2014	3-Way Collar	2,000		$ 65.00	$ 87.68	$ 99.75
2015	3-Way Collar	4,500		$ 66.67	$ 83.33	$ 94.12
Gas						
1Q 2014	3-Way Collar	22,500		$ 3.56	$ 4.13	$ 4.78
2Q - 4Q 2014	3-Way Collar	30,000		$ 3.63	$ 4.21	$ 4.81
2015	3-Way Collar	15,000		$ 3.50	$ 4.00	$ 4.75

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 12 Derivatives* to our consolidated financial statements for additional information regarding our derivative instruments.

Title to Properties

Our properties are subject to customary royalty interest, 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 have generally 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, 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

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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 67% of our estimated proved reserves as of December 31, 2013 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2013, the daily NYMEX WTI oil spot price ranged from a high of $110.53 per Bbl to a low of $86.68 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $4.52 per MMBtu to a low of $3.08 per MMBtu. As of the date of filing, we had commodity price derivative agreements for 2014 on approximately 60% of our anticipated production based on the mid-point of our guidance range of 23,000 Boe/d to 25,000 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.

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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 to: (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

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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.

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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 three 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 2013, 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 "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 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 ("DOT") 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, 2013. 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 in response to some of these requests. For example, on September 23, 2013, the EPA published a final rule extending the compliance dates for certain groups of storage vessels to April 15, 2014 and April 15, 2015.

In February 2014, the Colorado Air Quality Control Commission ("AQCC") is considering the adoption of new and revised air quality regulations that would impose stringent new requirements to control emissions from existing and new oil and gas facilities in Colorado. The proposed regulations being considered by the AQCC would impose new control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in Colorado. For example, the AQCC will consider proposed Storage Tank Emission Management ("STEM") requirements for certain new and existing storage tanks. If adopted, the STEM requirements may require us to install costly emission control technologies at our new and existing well production facilities. The AQCC is also considering a Leak Detection and Repair ("LDAR") program for well production facilities and compressor stations. The proposed LDAR program primarily targets hydrocarbon (i.e., methane) emissions from the oil and gas sector in Colorado and would represent 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 are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions will 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 GHG 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. 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. Additionally, as discussed above, the state of Colorado intends to consider new air quality regulations in February 2014, targeting methane and ethane emissions from well production facilities and compressor stations.

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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, on October 15, 2013, the United States Supreme Court in *Utility Air Regulatory Group v. EPA*, No. 12-1146, granted a petition for certiorari to review the United States Court of Appeals for the District of Columbia Circuit's opinion and order upholding EPA's GHG-related regulations. The issue on review to the United States Supreme Court is whether EPA correctly determined that its regulation of GHGs from mobile sources triggered permitting requirements under the Clean Air Act for stationary sources of GHG emissions. The Court's decision is expected in Spring or Summer 2014, and could impact the scope of GHG regulation both at the federal and state levels.

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 recently submitted to the White House Office of Management and Budget for review 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 substantial.

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.

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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.

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. The State is also considering new regulations for air emissions from oil and gas operations as well as potential legislation increasing the monetary penalties for regulatory violations. 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 ("UIC"), 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 prepared draft guidance for issuing underground injection permits that would regulate hydraulic

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fracturing using diesel fuel, where EPA has permitting authority under the SDWA; 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, EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. EPA is also collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. 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. EPA intends to issue a final draft report for peer review and comment in 2014. The results of this study, which is still ongoing, could result in additional regulations, which could lead to operational burdens similar to those described above. 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, and recently published in the Federal Register a petition from national environmental advocacy groups seeking to include the oil and gas sector in the Toxics Release Inventory (TRI) reporting program established for many industries under TSCA. 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. 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. 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. Beyond that, in 2012, Longmont, Colorado prohibited the use of hydraulic fracturing. The oil and gas industry and the State are challenging that ban and the authority of local jurisdictions to regulate oil and gas development in court. In November 2013, four other Colorado cities and counties passed voter initiatives either placing a moratorium on hydraulic fracturing or banning new oil and gas development. These initiatives too are the subject of pending legal challenge. 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.

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 the Rocky Mountains, other companies in the oil and gas industry have fracture stimulated tens of thousands of wells since the mid-1980s. We and our predecessor companies have completed over 373 fracture stimulations since acquiring assets in the Wattenberg Field in 1999. At our Dorcheat Macedonia property in the Mid-Continent region, fracture stimulation has been performed since the 1970s and has

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been used more universally since the early 1990s. We and our predecessor companies have completed over 140 fracture stimulations since acquiring our Dorcheat Macedonia properties in mid-2008. 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 Bureau of Land Management 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.

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.

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State laws

Our properties located in Colorado are subject to the authority of 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 reporting requirements for spills or releases of exploration and production waste or produced fluids. 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 COGCC has also recently received a petition for rulemaking requesting that the COGCC promulgate certain rules that would require an evaluation of the impacts of oil and gas drilling on trust resources and human health according to the best available science before issuing any permits for oil and gas exploration and drilling. The COGCC intends to consider the petition in March 2014.

Employees

As of December 31, 2013, we employed 236 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, 2013, we leased 57,454 square feet of office space in Denver, Colorado at 410 17th Street, where our principal offices are located. We also have leases for field offices in Houston, Texas, Bakersfield, California, Stamps, Arkansas and Kersey, Colorado totaling 12,682 square feet.

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.

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Risks Related to Our Business

A 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, heavily influences our revenue, profitability, access to capital 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. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- 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;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; 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. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. See *Our exploration, development and exploitation projects require substantial capital expenditures*. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. See also *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* below.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 67% of our estimated proved reserves as of December 31, 2013 were oil and natural gas liquids, our financial results are more sensitive to movements in oil prices. The price of oil has been extremely volatile and we expect this volatility to continue. During the year ended December 31, 2013, the daily NYMEX WTI oil spot price ranged from a high of $110.53 per Bbl to a low of $86.68 per Bbl and the NYMEX natural gas Henry Hub spot price ranged from a high of $4.52 per MMBtu to a low of $3.08 per MMBtu.

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As of December 31, 2013, we had commodity price derivative agreements on approximately 9,526 Bbls/d and 4,500 Bbls/d of oil hedged with average minimum prices of $89.48/Bbl and $83.33/Bbl in 2014 and 2015, respectively.

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 may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as blizzards and ice storms;
- 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; 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 Item 1, Part I 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, 2013, 2012 and 2011.

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.

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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 new 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 charge. 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 40 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.

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.

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 new SEC requirements for the years ended December 31, 2013, 2012 and 2011, 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 12 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;

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- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may 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, 2013 would decrease by approximately 20% or $242.6 million. PV-10 is a non-GAAP financial measure. Please refer to *Estimated Proved Reserves* under Item 1, Part 1 of this Annual Report on Form 10-K for management's discussion of this non-GAAP financial measure.

If oil and natural gas prices decrease, we may be required 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, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our revolving credit facility. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our ability to borrow under our revolving credit facility and 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 a horizontal drilling program include, but are not limited to,

- landing our well bore in the desired drilling zone;
- 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.

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Any of these risks could materially and adversely impact the success of our horizontal drilling program and thus our cash flows and results of operations.

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 natural gas and oil prices decline, 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 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 and development 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 $453.9 million and $304.6 million (including $25.8 million and $13.9 million for the acquisition of oil and gas properties and contractual obligations for land acquisitions) related to capital and exploration expenditures for the years ended December 31, 2013 and 2012, respectively. The mid-point of our capital expenditure budget for 2014 is approximately

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$600 million, with approximately $545 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 sale of non-strategic assets. The issuance of additional debt or equity 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. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. 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.

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

- our proved reserves;
- the level 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.

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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. 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 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.

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 97% of our current production 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, with one property remaining to be sold as of December 31, 2013. As a result of these portfolio changes, our operations and production are more concentrated.

The Wattenberg and Dorcheat Macedonia Fields represent 65% and 32%, respectively, of our 2013 total sales volumes. Disruption of our business in either of these Fields, such as from an accident, natural disaster or other event, would result in a greater impact on our production profile, cash flows and overall business plan than if we operated in a larger number of areas.

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.

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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. 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, the gas gathering systems serving the Wattenberg Field recently experienced high line pressures reducing capacity and causing gas production to either be shut in or flared. 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.

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 54% of our total proved reserves were classified as proved undeveloped as of December 31, 2013. 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

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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, 2013 proved reserve report, if, on January 1, 2014, 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 53% 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 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
- 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.

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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 gas and oil 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 are expected to continue to increase over the next few years, and we may decrease coverage and retain more risk to mitigate future 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. 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 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. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling 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. 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 additional wells that we identify as 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.

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Our potential drilling location inventories 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. As of December 31, 2013, a significant portion of our drilling program targets probable and possible reserves with only 305 gross (255 net) of our approximately 1,950 identified potential future gross drilling locations attributed to proved undeveloped reserves. 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. These rules and guidance 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 December 31, 2013, the majority of our acreage in Arkansas was held by unitization, production, or drilling operations and therefore not subject to lease expiration. As of December 31, 2013, 16,057 net acres of our properties in the Rocky Mountain region, specifically 7,062 acres in the Wattenberg Field and 8,995 acres in the North Park Basin, 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 574 net acres will expire in 2014, 2,674 net acres will expire in 2015, and 1,233 net acres will expire in 2016. 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 the drilling block needs approval to drill. We do not always perform curative work to correct deficiencies in the marketability of 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 performed to perfect title. Certain title deficiencies may also result in litigation from time to time. Additional title issues are present in our Southern Arkansas operations. 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, the misfiling of instruments, instruments with missing or inadequate legal descriptions and unclear conveyance terms.

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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. 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;
- 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 and not adequately provided for 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; 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

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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 to 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 regardless of whether we were at fault for the full cost of removing or remediating contamination, 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 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.

Recently, the EPA issued final rules that establish new air emission controls for natural gas processing operations, as well as for oil and natural gas production. Among other things, the latter rules cover the completion and operation of hydraulically fractured gas wells and associated equipment. After several parties challenged the new air regulations in court, the EPA reconsidered certain requirements and is evaluating whether reconsideration of other issues is warranted. At this point, we cannot predict the final regulatory requirements or the cost to comply with such air regulatory requirements.

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, and the draft results are expected to be released for public and peer review in 2014 . In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The EPA also has prepared draft guidance for issuing underground injection permits that would regulate hydraulic fracturing using diesel fuel, where EPA has permitting

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authority under the Safe Drinking Water Act ("SDWA"); this guidance eventually could encourage other regulatory authorities to adopt to permitting and other restrictions on the use of hydraulic fracturing. The U.S. Department of 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. 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 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. The State is also considering new regulations for air emissions from oil and gas operations as well as potential legislation increasing the monetary penalties for regulatory violations.

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. Beyond that, in 2012, Longmont, Colorado prohibited the use of hydraulic fracturing. The oil and gas industry and the State are challenging that ban and the authority of local jurisdictions to regulate oil and gas development in court. In November 2013, four other Colorado cities and counties passed voter initiatives either placing a moratorium on hydraulic fracturing or banning new oil and gas development. These initiatives too are the subject of pending legal challenge. 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.

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.

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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 ("GHG") may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHG 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 GHG 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 GHG. Among other things, the EPA began limiting emissions of GHG from new cars and light duty trucks beginning with the 2012 model year. In addition, the EPA has 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, pursuant to which these permitting requirements have been "tailored" to apply to certain "major" stationary sources of GHG emissions in a multi-step process, with the largest major sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions will be required to meet emissions limits that are based on the "best available control technology," which will be established by the permitting agencies on a case-by-case basis. 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 is evaluating strategies for reducing air emissions of methane from oil and gas operations. 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 GHG 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." Because of the lack of any comprehensive federal legislative program expressly addressing GHG, there currently is a great deal of uncertainty as to how and when additional federal regulation of GHG might take place and as to whether the EPA should continue with its existing regulations in the absence of more specific Congressional direction.

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 GHG 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 GHG 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 GHG 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. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Effective January 31, 2014, Michael R. Starzer, retired from his position as President and Chief Executive Officer and Marvin M. Chronister, a current Board member, is serving as Interim President and Chief Executive Officer until a permanent replacement is identified. We are in the process of completing a comprehensive search for a permanent Chief Executive Officer, however there can be no assurance that we will be able to identify and hire a qualified candidate in a timely manner. Our ability to attract, select and hire a permanent Chief Executive Officer candidate may prove difficult, take more time than anticipated, and be costly. This may require other senior management to divert part of their attention from their primary duties, which could have an adverse effect on our business or operations.

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Similarly, our business could be adversely affected if we are unable to attract and retain qualified senior management, including a permanent Chief Executive Officer.

We recorded substantial stock-based compensation expense in 2013, 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 2013 in the amount of $12.6 million compared to $4.5 million in 2012. 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.

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.

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, 2013, we had $500 million of outstanding 6.75% Senior Notes ("Senior Notes"), no borrowings outstanding under our revolving credit facility and $181 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, sells 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.

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Our revolving credit facility and the indenture 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 indenture 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 indenture 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 indenture 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 credit facility are limited by our borrowing base, which is subject to periodic redetermination.

The borrowing base under our credit facility is redetermined at least semi-annually, and the lenders holding $66^2/_3$% of the aggregate commitments or we may request one additional

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redetermination in each six-month period. 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.

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 $57.5 million in receivables from oil and gas sales at December 31, 2013.

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, 2013, sales to Lion Oil Trading & Transport, Inc., Plains Marketing LP, and High Sierra Crude Oil & Marketing accounted for approximately 23%, 37%, and 15%, 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.

Failure to maintain effective internal controls could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could in turn have a material adverse effect on our business and stock price.

Our management does not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are being met. In addition, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of our controls can provide absolute assurance that all control issues and instances of fraud, if any, in the Company have been detected. The design of any system of controls is based in part upon the likelihood of future events, and there can be no assurance that any design will succeed in achieving its intended goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions or the degree of compliance with its policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur without detection. If we are unable to maintain effective internal controls, our business and operating results could be harmed or investors could lose confidence in our financial reports, which could have a material adverse effect on our business and stock price.

Compliance with the reporting and disclosure requirements of a public company under the Exchange Act, the NYSE rules and the requirements of the Sarbanes-Oxley Act of 2002 and the Dodd-Frank Act requires a substantial amount of management's time and will continue to increase our costs.

As a public company with listed securities, we must comply with laws, rules, regulations and requirements of the Sarbanes-Oxley Act of 2002 and the Dodd-Frank Act, related regulations of the SEC and the requirements of the New York Stock Exchange ("NYSE"), among other laws, rules, regulations and requirements. Complying with these laws, rules, regulations and requirements occupies a significant amount of time of our board of directors and management and will continue to significantly increase our costs and expenses.

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.

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.

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.

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. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient.

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.

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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 stockholder sells their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the stockholder 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. The trading price of our common stock may be affected by a number of factors, including our operating results, financial condition, drilling activities, general conditions in the oil and natural gas exploration and development industry, general economic conditions, the securities markets and the risk factors set forth in this annual report, which are incorporated herein by reference.

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 18.83% of our total outstanding shares. HMQ is party to a registration rights agreement with us. Pursuant to this agreement, we have agreed to effect the registration of shares held by HMQ if itso requests or if we conduct other offerings 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 may be deemed to beneficially own or control a significant portion of our common stock, giving them a substantial influence over corporate transactions and other matters. Their interests and the interests of the parties on whose behalf they invest may conflict with our other stockholders, and the concentration of ownership of our common stock by such stockholders will limit the influence of 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 substantial influence over approximately 18.83% 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 exert significant influence over our board of directors and substantially influence 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, would have the ability to exert significant influence over the Company.

A concentration of ownership in AIMCo's clients would 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. The significant ownership interest of HMQ could also adversely affect investors' perceptions of our corporate governance.

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.

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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.

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".

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
2012		
1st Quarter	$ 22.25	$ 12.62
2nd Quarter	22.66	14.52
3rd Quarter	24.40	15.00
4th Quarter	29.03	20.83

Holders. As of February 24, 2014, there were approximately 172 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 indenture 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.

On February 24, 2014, the last sale price of our common stock, as reported on the NYSE, was $47.44 per share.

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Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the year ended December 31, 2013:

	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Be Purchased Under Programs
January 1, 2013 - January 31, 2013				
February 1, 2013 - February 28, 2013	74,994	$ 34.79		
March 1, 2013 - March 31, 2013	622	$ 39.29		
April 1, 2013 - April 30, 2013	4,719	$ 35.73		
May 2, 2013 - May 31, 2013				
June 1, 2013 - June 30, 2013				
July 1, 2013 - July 31, 2013	1,097	$ 39.95		
August 1, 2013 - August 31, 2013	5,327	$ 38.16		
September 1, 2013 - September 30, 2013	2,412	$ 45.91		
October 1, 2013 - October 31, 2013	1,593	$ 48.52		
November 1, 2013 - November 30, 2013	3,979	$ 51.94		
December 1, 2013 - December 31, 2013	13,496	$ 44.26		
Total	108,239	$ 37.34		

(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 program to repurchase shares of our common stock, nor do we have a publicly announced 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, 2013.

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.

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, 2013. The graph assumes that $100 was invested on December 14, 2011 in the common stock of Bonanza Creek Energy, Inc., 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* and financial statements and the notes to those financial statements in Item 8, Part II of this Annual Report on Form 10-K.

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

	Period from Inception (December 23, 2010) to December 31, 2010)	Year Ended December 31, 2011	Year Ended December 31, 2012	Year Ended December 31, 2013
	(in thousands, except per share amounts)			
Statement of Operations Data:				
Revenues:				
Oil sales	$ 1,200	$ 79,568	$ 195,175	$ 357,001
Natural gas sales	207	13,442	19,795	46,490
Natural gas liquids and CO_2 sales	213	12,714	16,235	18,369
Total revenues	1,620	105,724	231,205	421,860
Operating expenses:				
Lease operating	419	18,253	30,695	47,771
Severance and ad valorem taxes	66	5,918	13,674	27,203
Exploration		878	10,715	4,213
Depreciation, depletion and amortization	436	28,014	66,202	140,176
Impairment of oil and gas properties(2)		623	611	
General and administrative	324	13,164	26,922	42,864
Employee stock compensation(1)		4,449	4,483	12,638
Total operating expenses	1,245	71,299	153,302	274,865
Income from operations	375	34,425	77,903	146,995
Other income (expense):				
Interest expense	(58)	(4,017)	(4,133)	(21,972)
Derivative gain (loss)	(561)	(2,799)	925	(12,472)
Other loss		(110)	(133)	(43)
Total other expense	(619)	(6,926)	(3,341)	(34,487)
Income (loss) from continuing operations before taxes	(244)	27,499	74,562	112,508
Income tax benefit (expense)	90	(12,890)	(29,991)	(42,926)
Income (loss) from continuing operations	(154)	14,609	44,571	69,582
Discontinued operations(3)				
Loss from operations associated with oil and gas properties held for sale (including impairments in 2011, and 2012 of $3.4 million and $1.6 million, respectively)(2)	(13)	(3,610)	(927)	(644)
Gain on sale of oil and gas properties			4,192	
Income tax (expense) benefit	5	1,692	(1,313)	246
Income (loss) from discontinued operations	(8)	(1,918)	1,952	(398)

Net income (loss)	$ (162)	$ 12,691	$ 46,523	$ 69,184

Basic net income (loss) per common share				
Income from continuing operations per share	$	$ 0.49	$ 1.12	$ 1.73
Income (loss) from discontinued operations per share	$	$ (0.06)	$ 0.05	$ (0.01)
Net income per share	$	$ 0.43	$ 1.17	$ 1.72
Basic weighted-average common shares outstanding	29,123	29,324	39,052	39,337
Diluted net income (loss) per common share				
Income from continuing operations per share	$	$ 0.49	$ 1.12	$ 1.72
Income (loss) from discontinued operations per share	$	$ (0.06)	$ 0.05	$ (0.01)
Net income per share	$	$ 0.43	$ 1.17	$ 1.71
Diluted weighted-average commons shares outstanding	29,123	29,324	39,052	39,404

(1) In connection with our IPO, the Company distributed 243,945 fully vested shares of former Class B common stock, previously held in trust, to our employees and recorded a $4.1 million stock-based compensation charge. In addition the Company distributed the remaining 10,000 shares of our former Class B common stock to our executives and employees. In connection with our IPO, the 10,000 shares of our former Class B common stock converted into 437,787 shares of restricted common stock, vesting over a three year period. In connection with our Long Term Incentive Plan ("LTIP"), the Company granted 310,439 and 731,034 shares of restricted common stock during 2013 and 2012, respectively, which vest over a three year period, and 41,622 shares of performance share units during 2013, which vest entirely after a three-year measurement period. The Company expects to recognize compensation expense relating to these grants during the years ended December 31, 2014, 2015, and 2016 of approximately $11.0 million, $5.7 million, and $1.5 million, respectively.

(2) The impairment for 2011 was related to steam flooding results in our legacy California assets that were lower than expected and the impairment of one non-core field in Southern Arkansas was related to the loss of a lease. The impairments for 2012 were related to one non-core field in Southern Arkansas and our legacy California assets that were written down to their expected sales price.

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(3) The results of operation and impairment loss related to non-core properties in California sold in 2012 or held for sale have been reflected as discontinued operations. Please refer to *Note 3 Discontinued Operations* to our consolidated financial statements in Item 8, Part II of this Annual Report on Form 10-K.

	As of December 31,			
	2010	**2011**	**2012**	**2013**
	(in thousands)			
Balance Sheet Data:				
Cash and cash equivalents	$	$ 2,090	$ 4,268	$ 180,582
Property and equipment, net (excludes assets held for sale)	481,374	618,229	943,175	1,267,249
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
Long term debt, including current portion:				
Credit facility	55,400	6,600	158,000	
Senior Notes, net of unamortized premium				508,847
Total stockholders' equity	356,380	527,982	578,518	656,028

	Inception (December 23, 2010) to December 31, 2010	Year Ended December 31, 2011	Year Ended December 31, 2012	Year Ended December 31, 2013
	(in thousands)			
Selected Cash Flow Data:				
Net cash provided by (used in) operating activities	$ (1,586)	$ 60,627	$ 157,636	$ 307,015
Net cash (used in) investing activities	(864)	(161,926)	(305,277)	(465,223)
Net cash provided by financing activities		103,389	149,819	334,522

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, part of the Rocky Mountain region, and the Dorcheat Macedonia Field in southern Arkansas, part of the Mid-Continent region. In addition, we own and operate oil-producing assets in other fields in Arkansas and the North Park Basin in Colorado. During the second quarter of 2012, we began the divestiture process for all of our California properties, with one property remaining to be sold as of December 31, 2013. Under generally accepted accounting principles, the results of operations for the California properties are presented as discontinued operations and are included unless otherwise noted. 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. We maintain a high working interest in our properties.

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Financial and Operating Highlights

Our 2013 financial results included:

- Net income of $69.2 million (including $69.6 million from continuing operations), as compared with $46.5 million (including $44.6 million from continuing operations) for 2012;
- Cash flows provided by operating activities of $307.0 million, as compared with $157.6 million in 2012;
- Capital expenditures of $447.1 million, as compared with $340.9 million in 2012; and
- Total liquidity of $595.0 million at December 31, 2013, consisting of year-end cash balance plus funds available under our credit facility, as compared with $123.3 million at December 31, 2012. Please refer to *Liquidity and Capital Resources* below for additional discussion.

We delivered significant growth in 2013. Operational highlights for 2013 included:

- Increased production by 74% to 5,902.7 MBoe in 2013 from 3,387.9 MBoe in 2012, with oil and NGL production representing 72% of total production. Production volumes exclude production from discontinued operations. Please refer to the caption *Production Results* below for additional discussion;
- Decreased average production costs per Boe by 11% to $8.09 per Boe in 2013 from $9.06 per Boe in 2012, primarily as a result of the increasing mix of production generated by horizontal wells in the Wattenberg Field;
- Increased proved reserves to 69.8 MMBoe as of December 31, 2013, an increase of 32% from December 31, 2012;
- 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;
- Demonstrated early success on three pilot projects that tested 5-acre wells in the Dorcheat Macedonia Field;
- Increased the amount of our borrowing base under our revolving credit facility from $325 million to $450 million. Please refer to *Liquidity and Capital Resources* below for additional discussion.

Senior Management Change

Effective January 31, 2014, the Company's President and CEO, Michael R. Starzer, retired from his position and as a member of the Company's Board. The Board has begun a search for a new President and CEO. During this interim period, Marvin M. Chronister, a current member of the Board, will act as interim President and CEO. Mr. Chronister has over 38 years of oil and gas industry experience and has served on the Company's Board since March 2011.

Outlook for 2014

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 2014 to be in the range of $575 million to $625 million, allocating approximately 87% to the Wattenberg Field and 13% 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. This capital investment is expected to produce 2014

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average sales volumes of 23,000 Boe/d to 25,000 Boe/d, while maintaining a strong oil and liquids profile.

Results of Operations

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

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	1,696.2	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	0%
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 and natural gas prices also contributed. Oil, natural gas, and natural gas liquids production 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 Rockies and 45 gross (36.5 net) wells in southern Arkansas. The increased volumes are a direct result of the $447.1 million expended for drilling and completion during the year ended December 31, 2013. Oil volumes increased by 77% in 2013, and the sales price increased 3% from $89.08 per barrel during the year ended December 31,

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2012 to $91.84 per barrel during the year ended December 31, 2013, which together accounted for the $161.8 million increase in revenues. Natural gas volumes increased by 82% in 2013, and were aided by an increase in sales price of 29% from $3.62 per Mcf to $4.66 per Mcf for these one year periods, which together accounted for an additional $26.7 million of the increase in revenues. Natural gas liquid volumes increased by 24% in 2013, but were offset by a sales price decline of 7% from $55.54 per Bbl to $51.74 per Bbl for the comparable period. 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.

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 production 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. While our lease operating expense per Boe decreased due to higher production from our lower cost horizontal wells in the Wattenberg Field we were still impacted by high gas gathering pipeline pressures and emission compliance standards which resulted in production that was less than anticipated. In Southern Arkansas the replacement of essential gas plant processing equipment cost approximately $400,000 to install. Our newly constructed gas plant is not yet running at full capacity; however the operating cost of said gas plant does not vary based on capacity causing our

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lease operating expense per Boe to be higher than it would be if the gas plant were operating at 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 production volumes with a corresponding 5% increase in average sales price per Boe for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

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.

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%.

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 seismic and 3D data acquisitions for the Wattenberg Field, wrote-off one exploratory dry hole totaling $630,000 and $1.7 million on an expired non-core lease in the North Park Basin, and paid delay rentals in the amount of $300,000. During 2012, we wrote-off three exploratory dry holes in the North Park Basin amounting to $8.4 million, we spent $2.0 million on a seismic acquisition project in the North Park Basin, and paid delay rentals in the amount of $300,000.

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 Senior Notes in 2013 was $17.0 million, of which $798,000 related to the amortization of debt issuance costs related to the Senior Notes offering, offset by the amortization of the premium on the Senior Notes of $153,000. Interest expense on our revolving credit facility was $4.1 million 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.

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. Please refer to *Note 12 Derivatives* in Item 8, Part II of this Annual Report on Form 10-K for additional discussion.

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.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

The table below presents revenues, sales volumes, and average sales prices for the years ended December 31, 2012 and 2011:

	For the Year Ended December 31,			
	2012(3)	2011	Change	Percent Change
Revenues (In thousands, except percentages)				
Crude oil sales	$ 195,175	$ 79,568	$ 115,607	145%
Natural gas sales	19,795	13,442	6,353	47%
Natural gas liquids sales	15,811	12,358	3,453	28%
CO_2 sales	424	356	68	19%
Product revenues	$ 231,205	$ 105,724	$ 125,481	119%
Sales volumes:				
Crude oil (MBbls)	2,191.0	887.4	1,303.6	147%
Natural gas (MMcf)	5,473.2	2,773.1	2,700.1	97%
Natural gas liquids (MBbls)	284.7	183.8	100.9	55%
Crude oil equivalent (MBoe)(1)	3,387.9	1,533.4	1,854.5	121%
Average Sales Prices (before derivatives)(2):				
Crude oil (per Bbl)	$ 89.08	$ 89.67	$ (0.59)	(1)%
Natural gas (per Mcf)	3.62	4.85	(1.23)	(25)%
Natural gas liquids (per Bbl)	55.54	67.23	(11.69)	(17)%
Crude oil equivalent (per Boe)(1)	68.12	68.72	(0.60)	(1)%
Average Sales Prices (after derivatives)(2):				
Crude oil (per Bbl)	$ 88.40	$ 85.51	$ 2.89	3%
Natural gas (per Mcf)	3.76	5.09	(1.33)	(26)%
Natural gas liquids (per Bbl)	55.54	67.23	(11.69)	(17)%
Crude oil equivalent (per Boe)(1)	67.91	66.75	1.16	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, 2012.

Revenues increased by 119%, to $231.2 million for the year ended December 31, 2012 compared to $105.7 million for the year ended December 31, 2011. Oil, natural gas, and natural gas liquids production increased 147%, 97%, and 55%, respectively, during the year ended December 31, 2012, as compared to the year ended December 31, 2011. During the period from January 1, 2012 through December 31, 2012, we drilled 108 gross (104.7 net) wells in the Rockies and 42 gross 37.2 wells in southern Arkansas. The increased volumes are a direct result of the $165.5 million expended for drilling and completion and gas plant capital expenditures during the year ended December 31, 2011, and the $340.8 million expended during the year ended December 31, 2012. Oil prices were commensurate period over period and increased oil volumes accounted for nearly all of the

$115.6 million of the total $125.5 million increase in revenues for the Company for the year ended December 31, 2012 compared to the same period in 2011. Natural gas volumes increased by 97% in 2012, but were partially offset by a sales price decline of 25% from $4.85 per Mcf to $3.62 per Mcf for these one year periods and accounted for $6.4 million of the total $125.5 million increase in revenues for the year ended December 31, 2012. Natural gas liquid volumes increased by 55% in 2012, but were partially offset by a sales prices decline of 17% from $67.23 per Bbl to $55.54 per Bbl for these one year periods and accounted for $3.5 million of the total $125.5 million increase in revenues for the year ended December 31, 2012. Our Wattenberg Field natural gas is sold without processing and sells at a premium due to its very high BTU content. Our production of oil, natural gas, and natural gas liquids for year ended December 31, 2012 was approximately 65%, 27% and 8%, respectively, of total production.

The table below presents operating expense amount and per Boe data for the years ended December 31, 2012 and 2011:

	For the Years Ended December 31,			
	2012(1)	2011	Change	Percent Change
Expenses (in thousands, except percentages):				
Lease operating	$ 30,695	$ 18,253	$ 12,442	68%
Severance and ad valorem taxes	13,674	5,919	7,755	131%
General and administrative	31,405	17,613	13,792	78%
Depreciation, depletion and amortization	66,202	28,014	38,188	136%
Exploration	10,715	877	9,838	1,122%
Impairment of oil and gas properties	611	623	(12)	(2)%
Operating expenses	$ 153,302	$ 71,299	$ 82,003	115%
Expenses per Boe:				
Lease operating	$ 9.06	$ 11.90	$ (2.84)	(24)%
Severance and ad valorem taxes	4.04	3.86	0.18	5%
General and administrative	9.27	11.49	(2.22)	(19)%
Depreciation, depletion and amortization	19.54	18.27	1.27	7%
Exploration	3.16	0.57	2.59	454%
Impairment of oil and gas properties	0.18	0.41	(0.23)	(56)%
Operating expenses	$ 45.25	$ 46.50	$ (1.25)	(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, 2012.

Lease operating expense. Our lease operating expenses increased $12.4 million, or 68%, to $30.7 million for the year ended December 31, 2012 from $18.3 million for the year ended December 31, 2011 and decreased on an equivalent basis from $11.90 per Boe to $9.06 per Boe. The increase in lease operating expense was related to increased production volumes attributable to our drilling program and the operation of an additional gas plant that was constructed during 2011 that came on line during September of 2011. Gas plant operating expense, which is a component of lease operating expense, increased $1.1 million, or 15%, to $8.4 million for the year ended December 31, 2012 from $7.3 million for the year ended December 31, 2011. A portion of the increase in gas plant operating expense was related to the replacement of a heat exchanger which cost approximately $0.6 million to procure and install. During the year ended December 31, 2012, well servicing, rental equipment, pumping and gauging, and insurance expenses were $8.3 million, $1.7 million, $0.4 million and $0.6 million higher, respectively, than the year ended December 31, 2011. The decrease in lease operating expense on an equivalent basis was primarily related to our transition from vertical wells to horizontal wells in the Wattenberg Field during 2012.

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Severance and ad valorem taxes. Our severance and ad valorem taxes increased $7.8 million, or 131%, to $13.7 million for the year ended December 31, 2012 from $5.9 million for the year ended December 31, 2011. The increase was primarily related to a 121% increase in production volumes and higher ad valorem tax assessments. The increase in severance and ad valorem taxes on a Boe basis for the year ended December 31, 2012 as compared to the year ended December 31, 2011 was related to oil severance taxes and ad valorem taxes that were $4.2 million and $3.2 million, respectively, higher than the comparable period in the previous year.

General and administrative. Our general and administrative expense increased $13.8 million, or 78%, to $31.4 million for the year ended December 31, 2012 from $17.6 million for the year ended December 31, 2011. During the year ended December 31, 2012, wages, benefits and employee placement fees were $10.2 million higher than the year ended December 31, 2011 due to our headcount increasing as the result of our accelerated drilling program and the addition of accounting, legal and IT positions that were previously outsourced. During the year ended December 31, 2012, accounting fees were $0.4 million higher due to a one-time payment that was made to our outsource accounting provider to terminate our agreement with them. Also during the year ended December 31, 2012, legal fees and franchise taxes were $2.1 million and $0.5 million higher, respectively. The majority of the increased general and administrative expense was due to hiring a large number of personnel to support our growth and the regulatory compliance obligations of a newly public company and legal fees associated with arbitration related to claims of a former chairman of BCEC.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expense increased $38.2 million, or 136%, to $66.2 million for the year ended December 31, 2012 from $28.0 million for the year ended December 31, 2011. Our depreciation, depletion and amortization expense per Boe produced increased $1.27 to $19.54 for the year ended December 31, 2012 as compared to $18.27 for the year ended December 31, 2011. This increase was primarily the result of a 121% increase in production period over period that was compounded by proved reserve and proved developed reserve volume growth that was not commensurate with the costs additions to the depletion base. At December 31, 2012, we revised our proved reserves downward by 6,938 MBoe due primarily to a combination of eliminating 50 locations from proved undeveloped reserves as a result of changes in focus from vertical to horizontal development and lower performance than expected from our vertical wells in the Wattenberg Field.

Impairment of oil and gas properties. The Company recorded $0.6 million of proved property impairment in one non-core field in southern Arkansas for the year ended December 31, 2012. The Company recorded $0.6 million of proved property impairment in one non-core field in southern Arkansas for the year ended December 31, 2011.

Exploration. Our exploration expense increased $9.8 million, or 1,122%, to $10.7 million in the year ended December 31, 2012 from $0.9 million in the year ended December 31, 2011. During the year ended December 31, 2012 the following items were charged to exploration expense: a seismic acquisition project in the amount of $2.0 million was conducted in the North Park Basin; three exploratory locations in the North Park Basin in the amount of $8.4 million were written off; and delay rentals in the amount of $0.3 million were paid. During the year ended December 31, 2011, our exploration costs consisted primarily of the acquisition of 7,700 acres of 3-D seismic data on the eastern edge of the Wattenberg Field in Weld County Colorado to help evaluate our Niobrara oil shale acreage.

Interest expense. Our average debt outstanding for the year ended December 31, 2012 was $74.7 million as compared to $95.3 million for the year ended December 31, 2011. Our interest expense for the year ended December 31, 2012 was commensurate with the year ended December 31, 2011 due to accretion expense in the amount of $0.3 million related to our contractual obligation for the lease acquisition in the Wattenberg Field and fees of $50,000 related to our $48 million letter of credit obligation which secures the acquisition.

Derivative gain (loss). Our derivative gain increased $3.7 million, or 132%, to a gain of $924,000 for the year ended December 31, 2012 compared to a loss of $2.8 million for the year ended December 31, 2012. The gain experienced on derivative contracts during 2012 was primarily the result of realized prices being less than the contract prices.

Income tax expense. Our estimate for federal and state income taxes for the year ended December 31, 2012 was $30.0 million from continuing operations as compared to $12.9 million for the year ended December 31, 2011. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. 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 believes that this rate more appropriately reflects the future federal rate on future earnings. The increase in the effective 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. Our effective tax 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 are presented as discontinued operations in the accompanying statements of operations and comprehensive income.

The majority of these properties were sold in 2012, and the operating results before income taxes for our California properties for the year ended December 31, 2013 were net revenues of $1.7 million, and operating expenses of $2.3 million, as compared to 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, for the year ended December 31, 2012. Sales volumes for the years ended December 31, 2013 and 2012 were 47 Boe/d and 147 Boe/d, respectively.

The operating results before income taxes for our California properties for the year ended December 31, 2011 were net revenues of $6.7 million, and operating expenses of $10.3 million. Operating expenses for the year ended December 31, 2011 included impairments in the amount of $3.4 million. Sales volumes for the year ended December 31, 2011 were 181 Boe/d.

Please refer to *Note 3 Discontinued Operations* in Item 8, Part II 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, cash flow from operating activities and availability under our revolving credit facility will be sufficient to fund our planned capital expenditures 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; 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 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 Senior Notes that mature on April 15, 2021. The Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by our existing and future subsidiaries that incur or guarantee certain indebtedness, including indebtedness under our revolving credit facility. We may redeem the Senior Notes (i) at any time on or after April 15, 2017 at the redemption price equal to 100% together with accrued and unpaid interest, and (ii) prior to April 15, 2017 at the "make-whole" redemption prices described in the indenture together with accrued and unpaid interest. The net proceeds from the sales of the Senior Notes were approximately $497.3 million after the premium and deduction of $11.7 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 including funding the Company's drilling and development program and other capital expenditures.

On May 15, 2013, the borrowing base under our revolving credit facility was increased to $330 million. On November 6, 2013, the lenders completed their semi-annual borrowing base redetermination which resulted in an increase of the available borrowing base to $450 million. Pursuant to the corresponding amendment, the Company elected to limit bank commitments at $330 million while reserving the option to access, at the Company's request, the full $450 million prior to the next semi-annual redetermination. The maturity date of the credit facility was also extended by one year to September 15, 2017. As of December 31, 2013, we had nil outstanding, $36 million of letters of credit issued, and $414 million of borrowing capacity available under our credit facility. Our weighted-average interest rate on borrowings from our credit facility was 2.34% and 1.94% (excluding amortization of deferred financing costs and the accretion of our contractual obligation for land acquisition) during the years ended December 31, 2013 and 2012, respectively. See the *Credit facility* section below for additional discussion.

In the second quarter 2012, we began the divestiture process of our non-core properties in California. 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. During 2012, we sold a majority of our properties in California, for approximately $9.3 million in aggregate. As of December 31, 2013, we continued to own an immaterial operated working interest in the Midway-Sunset Field, which is expected to be sold in the first half of 2014.

On July 31, 2012, we acquired leases in the Wattenberg Field from the State of Colorado, State Board of Land Commissioners. We paid approximately $12 million at closing, another $12 million on July 31st of 2013, and will pay approximately $12 million on July 31st of each of the next three years. These future payments are secured by a letter of credit which reduced our availability under the borrowing base by $36 million as of December 31, 2013.

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 *Item 7A. Quantitative and Qualitative Disclosures on Market Risks* for a summary of derivatives in place.

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

	For the Years Ended December 31,		
	2013	2012	2011
		(in thousands)	
Financial Measures:			
Net cash provided by operating activities	$ 307,015	$ 157,636	$ 60,627
Net cash (used in) investing activities	(465,223)	(305,277)	(161,927)
Net cash provided by financing activities	334,522	149,819	103,389
Cash and cash equivalents	180,582	4,268	2,090
Acquisitions of oil and gas properties	13,797	13,920	1,810
Exploration and development of oil and gas properties, investment in gas processing facility, and obligation on land acquisition	435,037	297,114	156,871

Cash flows provided by operating activities

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 production of 74% compounded with a 5% increase in realized sales prices on an equivalent basis. 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.

Net cash provided by operating activities increased $97.0 million for the year ended December 31, 2012, compared to the same period in 2011. The increase in cash flows from operating activities resulted primarily from an increase in production of 121% partially offset by a 1% decrease in realized sales prices on an equivalent basis. Production was further offset by increased lease operating expense, production taxes, cash portion of general and administrative expense, and cash portion of interest expense during 2012 as compared to 2011. See *Results of Operations* above for more information on the factors driving these changes.

Cash flows (used in) investing activities

Expenditures for development of oil and natural gas properties and natural gas plants are the primary use of our capital resources. Net cash used in investing activities for the year ended December 31, 2013 increased $159.9 million, compared to the same period in 2012. 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) 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. For the year ended December 31, 2011, cash used for the acquisition of oil and gas properties was $1.8 million, cash used for the development of oil and natural gas properties (including cash used for natural gas plant expenditures) was $156.9 million, and cash used for non-oil and gas property additions was $1.2 million.

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Cash flows provided by financing activities

Net cash provided by financing activities for the year ended December 31, 2013 increased $184.7, compared to the same period in 2012. The issuance of our Senior Notes during 2013 provided $497.3 million in net proceeds, which was offset by decreased borrowings on our line of credit of $49.4 million and increased payments to our credit facility of $260.0 million for the two comparable periods. Net cash flows provided by financing activities for the year ended December 31, 2012 increased $46.4 million, compared to the same period in 2011. Borrowings on our line of credit increased $43.3 million and payments to our credit facility decreased $156.9 million, which were offset by $155.9 million in proceeds from the sale of our common stock during 2011, for the two comparable periods.

Credit facility

Senior Secured Revolving Credit Facility

The administrative agent of our $600 million Senior Secured Revolving Credit Facility ("Revolver") is KeyBank National Association. The Revolver provides for interest rates plus an applicable margin to be determined based on London Interbank Offered Rate ("LIBOR") or a bank base rate ("Base Rate"), at the Company's election. LIBOR borrowings bear interest at LIBOR plus 1.75% to 2.75% depending on the utilization level, and the Base Rate borrowings bear interest at the "Bank Prime Rate," as defined in the Revolver, plus .75% to 1.75%.

Our approved borrowing base under the Revolver, which was $450 million as of December 31, 2013, 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, 2013 and pursuant to the November 2013 Revolver amendment, the Company elected to limit bank commitments at $330 million while reserving the option to access, at the Company's request, the full $450 million prior to the next semi-annual redetermination scheduled for May 2014.

As of December 31, 2013, and through the filing date of this report, we had no borrowings outstanding under our Revolver. The Revolver matures on September 15, 2017. Amounts borrowed and repaid under the Revolver may be reborrowed. The Revolver 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 Revolver 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 Revolver 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 Revolver at any time without premium or penalty (other than customary LIBOR breakage costs).

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The Revolver 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 Revolver also contains covenants requiring us to maintain:

- a current ratio (*i.e.*, the ratio of current assets to current liabilities) of not less than 1.0 to 1.0 (current assets include, as of the date of calculation, the aggregate of all lender's unused commitment amounts); and
- a debt to earnings before interest, taxes, depreciation and amortization and other items (as defined in the Revolver) ("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, 2013 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 Revolver, the lenders will be able to accelerate the maturity of the loan and exercise other rights and remedies.

The Revolver 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;
- 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 Revolver), 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.

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Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2013 (in thousands):

	Payment by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Contractual Obligation					
Senior Notes	$ 500,000	$	$	$	$ 500,000
Interest on Senior Notes	253,125	40,781	67,500	67,500	77,344
Wattenberg field lease acquisition	36,000	12,000	24,000		
Derivative liability	6,523	5,320	1,203		
Operating leases(1)	16,871	2,349	4,733	4,955	4,834
Asset retirement obligations(2)	11,218	168	489		10,561
Total	$ 823,737	$ 60,618	$ 97,925	$ 72,455	$ 592,739

(1) See *Note 7 Commitments and Contingent Liabilities* to our consolidated financial statements for a description of operating leases.

(2) 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. The $168,000 included in the less than one year category is not discounted and is included in accounts payable and accrued expenses as of December 31, 2013.

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 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 independent engineers and technical staff prepare 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 independent engineers and technical staff 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 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.

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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. As a result, we maintain a minimum amount of product inventory in storage.

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

- 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

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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, 2013.

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, 2013.

Recent accounting pronouncements

In July 2013, the FASB issued *Update No. 2013-11 Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (a consensus of the FASB Emerging Issues Task Force)*. The update provides clarification on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The update is effective for public entities for fiscal years, and interim periods within those years, beginning after December 15, 2013. Early adoption is permitted. The Company has not yet evaluated the impact of the update on its financial statements.

Effects of Inflation and Pricing

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the periods ended December 31, 2013, 2012 and 2011. 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, 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. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

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, 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 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, 2013 would have been lower by approximately 20% or $242.6 million. A 10% decrease in pricing for our proved undeveloped reserves would result in a reduction of 223 MBoe, a 0.6% 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

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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 Item 1, Part 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, 2013, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2013 would change our derivative gain (loss) by $42.7 million and $(34.1) million, respectively.

Interest Rates

At December 31, 2013 and through the filing date of this report, we had no outstanding borrowings under our credit facility, which is subject to floating market rates of interest. Borrowings under our 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, 2013 and through the filing date of this report, a 100 basis point change in interest rates would not change our annualized interest expense.

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 Item 1, Part I 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.***

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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, 2013 and 2012, 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, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Bonanza Creek Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with 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, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992, and our report dated February 28, 2014 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 28, 2014

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2013	As of December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 180,581,580	$ 4,267,667
Accounts receivable:		
Oil and gas sales	57,484,768	38,600,436
Joint interest and other	12,915,777	5,484,620
Prepaid expenses and other	1,637,925	3,031,815
Inventory of oilfield equipment	10,696,524	1,740,934
Derivative asset	857,863	2,178,064
Total current assets	264,174,437	55,303,536
Property and equipment (successful efforts method), at cost		
Proved properties	1,257,288,465	811,000,239
Less: accumulated depreciation, depletion and amortization	(224,848,470)	(89,669,725)
Total proved properties, net	1,032,439,995	721,330,514
Unproved properties	45,081,638	72,928,364
Wells in progress	110,847,961	75,031,806
Natural gas plant, net of accumulated depreciation of $5,902,796 in 2013 and $3,403,817 in 2012	71,473,693	69,683,786
Other property and equipment, net of accumulated depreciation of $2,822,245 in 2013 and $890,093 in 2012	7,405,862	4,199,702
Oil and gas properties held for sale, net of accumulated depreciation, depletion, and amortization of $1,462,563 in 2013 and $1,178,751 in 2012 (note 3)	360,265	582,388
Total property and equipment, net	1,267,609,414	943,756,560
Long-term derivative asset	292,691	
Other noncurrent assets	13,858,579	3,429,711
Total assets	$ 1,545,935,121	$ 1,002,489,807
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 5)	$ 121,664,750	$ 72,850,272
Oil and gas revenue distribution payable	36,240,879	12,552,655
Contractual obligation for land acquisition	11,999,877	11,999,877
Derivative liability	5,320,030	5,200,202

Total current liabilities	175,225,536	102,603,006
Long-term liabilities:		
Long-term debt	508,846,591	158,000,000
Contractual obligation for land acquisition	22,033,057	33,271,631
Ad valorem taxes	18,867,710	11,179,370
Derivative liability	1,202,971	1,208,106
Deferred income taxes, net	152,680,892	110,376,606
Asset retirement obligations	11,050,032	7,333,584
Total liabilities	889,906,789	423,972,303
Commitments and contingencies (note 7)		
Stockholders' equity:		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none outstanding		
Common stock, $.001 par value, 225,000,000 shares authorized, 40,285,919 and 40,115,536 issued and outstanding in 2013 and 2012, respectively	40,286	40,116
Additional paid-in capital	527,752,211	519,425,356
Retained earnings	128,235,835	59,052,032
Total stockholders' equity	656,028,332	578,517,504
Total liabilities and stockholders' equity	$ 1,545,935,121	$ 1,002,489,807

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,		
	2013	**2012**	**2011**
Operating net revenues:			
Oil and gas sales	$ 421,860,102	$ 231,205,241	$ 105,723,993
Operating expenses:			
Lease operating expense	47,770,702	30,695,192	18,252,963
Severance and ad valorem taxes	27,202,553	13,673,814	5,918,566
Exploration	4,212,915	10,714,918	876,971
Depreciation, depletion and amortization	140,175,796	66,201,942	28,014,077
Impairment of oil and gas properties		611,355	623,039
General and administrative (including $12,638,149, $4,482,611, and $4,436,794, respectively, of stock compensation)	55,503,282	31,404,970	17,612,943
Total operating expenses	274,865,248	153,302,191	71,298,559
Income from operations	146,994,854	77,903,050	34,425,434
Other income (expense):			
Derivative gain (loss)	(12,472,052)	924,305	(2,798,743)
Interest expense	(21,972,436)	(4,132,955)	(4,017,230)
Other loss	(42,083)	(132,526)	(110,276)
Total other income (expense)	(34,486,571)	(3,341,176)	(6,926,249)
Income from continuing operations before taxes	112,508,283	74,561,874	27,499,185
Current income taxes	(247,936)	(531,773)	
Deferred income tax expense	(42,678,544)	(29,459,500)	(12,890,328)
Income from continuing operations	69,581,803	44,570,601	14,608,857
Discontinued operations (Note 3)			
Loss from operations associated with oil and gas properties held for sale	(644,430)	(926,671)	(3,609,764)
Gain on sale of oil and gas properties		4,192,120	
Income tax (expense) benefit	246,430	(1,313,473)	1,692,088
Income (loss) from discontinued operations	(398,000)	1,951,976	(1,917,676)
Net income	$ 69,183,803	$ 46,522,577	$ 12,691,181

Comprehensive income	$ 69,183,803	$ 46,522,577	$ 12,691,181

Basic and diluted income (loss) per share:(1)			
Basic net income (loss) per common share:			
From continuing operations	$ 1.73	$ 1.12	$ 0.49
From discontinued operations	$ (0.01)	$ 0.05	$ (0.06)
From net income	$ 1.72	$ 1.17	$ 0.43
Basic weighted-average common shares outstanding	39,337,121	39,051,739	29,323,999
Diluted net income (loss) per common share:			
From continuing operations	$ 1.72	$ 1.12	$ 0.49
From discontinued operations	$ (0.01)	$ 0.05	$ (0.06)
From net income	$ 1.71	$ 1.17	$ 0.43
Diluted weighted-average common shares outstanding	39,403,599	39,051,739	29,323,999

(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 13 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		Class B	Additional Paid-In	Accumulated	
	Shares	Amount	Shares	Capital	Deficit	Total
Balances, January 1, 2011	29,122,521	$ 29,123	7,500	$ 356,513,012	$ (161,726)	$ 356,380,409
Issuance of common stock to directors for services				167,500		167,500
Issuance of Class B common stock			4,600			
Forfeiture of Class B common stock			(2,100)			
Sale of common stock, net of underwriting discounts and offering costs of $14,121,680	10,000,000	10,000		155,868,320		155,878,320
Exchange of Class B common stock for issuance of restricted common stock to officers and employees	437,787	438	(10,000)			438
Restricted stock used for tax withholdings	(82,724)	(83)		(1,405,105)		(1,405,188)
Stock-based compensation				4,268,856		4,268,856
Net Income					12,691,181	12,691,181
Balances, December 31, 2011	39,477,584	$ 39,478		$ 515,412,583	$ 12,529,455	$ 527,981,516
Restricted common stock issued	736,780	736				736
Restricted common stock forfeited	(80,338)	(80)				(80)
Restricted stock used for tax withholdings	(18,490)	(18)		(466,886)		(466,904)
Offering costs related to sale of common stock				(2,952)		(2,952)
Stock-based compensation				4,482,611		4,482,611
Net Income					46,522,577	46,522,577
Balances, December 31, 2012	40,115,536	$ 40,116		$ 519,425,356	$ 59,052,032	$ 578,517,504
Restricted common stock issued, net of excess income tax benefit	310,439	310		127,830		128,140
Restricted common stock forfeited	(31,817)	(32)				(32)
Restricted stock used for tax withholdings	(108,239)	(108)		(4,439,124)		(4,439,232)
Stock-based compensation				12,638,149		12,638,149
Net Income					69,183,803	69,183,803
Balances, December 31, 2013	40,285,919	$ 40,286		$ 527,752,211	$ 128,235,835	$ 656,028,332

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 CASH FLOWS

	For the Years Ended December 31,		
	2013	**2012**	**2011**
Cash flows from operating activities:			
Net income (loss)	$ 69,183,803	$ 46,522,577	$ 12,691,181
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	140,546,444	68,444,803	31,507,596
Deferred income taxes	42,432,114	30,772,973	11,198,240
Impairment of oil and gas properties		2,259,545	4,067,023
Stock-based compensation	12,638,149	4,482,611	4,436,794
Abandoned lease and dry hole expense	1,709,106	8,378,612	
Amortization of deferred financing costs and debt premium	1,505,175	700,162	1,004,225
Accretion of contractual obligation for land acquisition	761,304	317,209	
Gain on sale of oil and gas properties		(4,192,120)	
Derivative (gain) loss	12,472,052	(924,305)	2,798,743
Other	(7,115)	167,851	(40,368)
Changes in current assets and liabilities:			
Accounts receivable	(26,315,489)	(20,737,512)	(11,712,123)
Prepaid expenses and other assets	1,393,890	(1,163,799)	(1,164,953)
Accounts payable and accrued liabilities	50,897,311	22,768,732	5,996,440
Excess income tax benefit from the vesting of stock awards	(127,830)		
Settlement of asset retirement obligations	(73,358)	(161,787)	(155,558)
Net cash provided by operating activities	307,015,556	157,635,552	60,627,240
Cash flows from investing activities:			
Acquisition of oil and gas properties	(13,797,175)	(13,920,184)	(1,809,657)
Exploration and development of oil and gas properties	(417,835,859)	(281,326,110)	(134,183,772)
Natural gas plant capital expenditures	(5,201,717)	(15,787,631)	(22,687,197)
Payments of contractual obligations for land acquisition	(11,999,877)		
Proceeds from note receivable			986,906
Proceeds from sale of properties		9,336,898	
Decrease in restricted cash	79,478	252,580	
Derivative cash settlements	(11,329,849)	(725,382)	(3,024,136)
Additions to property and equipment non oil and gas	(5,138,312)	(3,106,758)	(1,208,755)
Net cash used in investing activities	(465,223,311)	(305,276,587)	(161,926,611)
Cash flows from financing activities:			
Proceeds from credit facility	102,000,000	151,400,000	108,100,000
Payments to credit facility	(260,000,000)		(156,900,000)
Net share settlement from issuance of stock awards	(4,439,232)	(466,904)	(1,405,188)
Proceeds from sale of Bonanza Creek Energy, Inc. common stock			155,878,320
Net proceeds from Senior Notes	488,278,341		
Premium on Senior Notes	9,000,000		
Excess income tax benefit from the vesting of stock awards	127,830		
Offering costs related to sale of common stock		(2,952)	
Deferred financing costs	(445,271)	(1,111,116)	(2,284,087)
Net cash provided by financing activities	334,521,668	149,819,028	103,389,045

Net increase in cash and cash equivalents		176,313,913		2,177,993		2,089,674
Cash and cash equivalents at beginning of period		4,267,667		2,089,674		
Cash and cash equivalents at end of period	$	180,581,580	$	4,267,667	$	2,089,674

Supplemental schedule of additional cash flow information and non-cash investing and financing activities:						
Cash paid for interest	$	12,860,203	$	2,914,095	$	3,101,074
Cash paid for income taxes	$	100,000	$	400,000	$	
Contractual obligation for land acquisition	$	33,271,631	$	45,271,508	$	
Changes in working capital related to drilling expenditures and property acquisition	$	29,272,661	$	37,545,233	$	9,555,592

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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2013, 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 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, 2013, 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.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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.

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 computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and the Company's expected cost to abandon its well interests.

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, 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.

For the year ended December 31, 2013, the Company recorded no proved property impairments from continuing or discontinued operations. For the years ended December 31, 2012 and 2011 the Company recorded $611,000 and $623,000, respectively, of proved property impairments from continuing operations located in one of the Company's non-core Southern Arkansas fields and $1.6 million and $3.4 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.

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;

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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.

The Company records the fair value of a liability for 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 balance sheets. For additional discussion, please refer to *Note 10 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 Plant

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 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 currently has its legacy California assets as held for sale, which is shown within the discontinued operation section of the accompanying statement of operations and within *Note 3 Discontinued Operations*.

Revenue Recognition

The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred, net of royalties, discounts, and allowances, as applicable. 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. The Company presents

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

production taxes separately within the accompanying statements of operations and comprehensive income within the severance and ad valorem taxes line item. 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, 2013, 2012, and 2011.

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 2012, 2011, and 2010 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, 2013, 2012, and 2011 Lion Oil Trading & Transportation, Inc. accounted for 23%, 32%, and 35%, respectively, while Plains Marketing LP accounted for 37%, 50%, and 45%, respectively, of oil and natural gas sales. For the year ended December 31, 2013, High Sierra Crude Oil & Marketing accounted for 15% of oil and natural gas sales and an immaterial amount for the years ended December 31, 2012 and 2011.

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. The Company

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value. For additional discussion, please refer to *Note 12 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 13 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 8 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 the fair value is disclosed within *Note 11 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 predecessor 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 July 2013, the FASB issued *Update No. 2013-11 Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (a consensus of the FASB Emerging Issues Task Force).* The update provides clarification on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. The update is effective for public entities for fiscal

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

years, and interim periods within those years, beginning after December 15, 2013. Early adoption is permitted. The Company has not yet evaluated the impact of the update on its financial statements.

NOTE 2 ACQUISITIONS

The Company did not complete any material acquisitions during the year ended December 31, 2013.

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, $12 million on July 31, 2013, and will pay approximately $12 million on July 31st of each of the next three years. These future payments were discounted based on our effective borrowing rate to arrive at the purchase price of $57 million. These future payments are secured by a $36 million letter of credit as of December 31, 2013 and interest will be imputed on the future payments. Following each payment the amount secured by the letter of credit will be amended each year on July 31st 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 carrying amounts of the remaining properties included within assets held for sale classified as discontinued operations are presented below.

	As of December 31,	
	2013	**2012**
Assets held for sale:		
Oil and gas properties, successful efforts method:		
Proved properties	$ 1,721,265	$ 1,721,265
Unproved properties	629	629
Wells in progress	100,934	39,245
Total property and equipment	1,822,828	1,761,139
Less accumulated depletion, depreciation, and amortization	(1,462,563)	(1,178,751)
Net property and equipment	$ 360,265	$ 582,388

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 3 DISCONTINUED OPERATIONS (Continued)

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,		
	2013	2012	2011
Net revenues:			
Oil and gas sales	$ 1,667,645	$ 5,410,806	$ 6,739,479
Operating expenses:			
Lease operating expense	1,870,457	2,279,844	3,234,575
Severance and ad valorem taxes	5,433	127,041	169,705
Exploration	65,537	39,541	7,460
Depreciation, depletion and amortization	370,648	2,242,861	3,493,519
Impairment of proved properties		1,648,190	3,443,984
Total operating expenses	2,312,075	6,337,477	10,349,243
(Loss) from operations associated with properties held for sale	$ (644,430)	$ (926,671)	(3,609,764)

NOTE 4 OTHER ASSETS

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

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

	As of December 31,	
	2013	2012
Certificates of deposit	$ 165,653	$ 245,131
Deferred financing costs	13,692,926	3,184,580
	$ 13,858,579	$ 3,429,711

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 5 ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses contain the following:

	As of December 31,	
	2013	2012
Drilling and completion costs	$ 80,971,343	$ 51,698,682
Accounts payable trade	3,287,897	10,049,131
Accrued general and administrative cost	12,719,821	5,078,059
Lease operating expense	5,440,000	2,824,300
Accrued reclamation cost	167,704	400,000
Interest	7,065,250	219,494
Accrued oil and gas derivatives	446,047	238,365
Production and ad valorem taxes and other	11,566,688	2,342,241
	$ 121,664,750	$ 72,850,272

NOTE 6 LONG-TERM DEBT

Long-term debt consisted of the following as of December 31, 2013 and 2012:

	As of December 31,	
	2013	2012
Revolving credit facility	$	$ 158,000,000
6.75% Senior Notes	500,000,000	
Unamortized premium on 6.75% Senior Notes	8,846,591	
	$ 508,846,591	$ 158,000,000

Revolving Credit Facility

The Revolver, 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 $600 million. The Revolver 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 1.75% to 2.75% depending on the utilization level, and the Base Rate borrowings bear interest at the "Bank Prime Rate," as defined in the Revolver, plus .75% to 1.75%.

On November 6, 2013 the borrowing base under the Revolver was determined to be $450 million, an increase from $330 million. Pursuant to the corresponding amendment, the Company elected to limit bank commitments at $330 million while reserving the option to access, at the Company's request, the full $450 million prior to the next semi-annual redetermination. The borrowing base is re-determined semiannually on May 15 and November 15 and may be re-determined up to one additional time between such scheduled determinations upon request by the Company or lenders holding 66$^{2}/_{3}$% of the aggregate commitments. A letter of credit that was issued to the Colorado State Board of Land

Commissioners in connection with the Company's lease of acreage in the Wattenberg Field reduces the borrowing base under the Revolver and is paid in equal $12 million increments over the next three years. Commitment fees on the Revolver range from 0.375% to 0.50%, depending on utilization. The Revolver restricts, among other items, the payment of dividends, certain additional

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 6 LONG-TERM DEBT (Continued)

indebtedness, sale of assets, loans and certain investments and mergers. The Revolver also contains certain financial covenants, which require the maintenance of a minimum current and debt coverage ratio, as defined by the Revolver. The Company was in compliance with all financial and non-financial covenants as of December 31, 2013 and through the filing date of this report. The Revolver is collateralized by substantially all the Company's assets and matures on September 15, 2017. As of December 31, 2013, the Company had no outstanding balance under the Revolver with an available borrowing capacity of $414 million after the reduction for the outstanding letter of credit of $36 million. As of December 31, 2012, the Company had $158 million outstanding under the Revolver with $119 million available borrowing capacity after the reduction of the outstanding letter of credit of $48 million.

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 the Company will pay interest on April 15 and October 15 of each year, which began on October 15, 2013. On November 15, 2013, BCEI issued an additional $200 million aggregate principal amount of 6.75% Senior Notes as an additional issuance of our existing Senior Notes that mature on April 15, 2021. The 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 Revolver. The net proceeds from the sale of the Senior Notes were $497.3 million after the premium and deduction of $11.7 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.

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 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 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.

The Company filed a Registration Statement on Form S-4 with the SEC, which became effective June 3, 2013 and registered the offering to exchange unregistered Senior Notes for registered Senior Notes, as well as the guarantees of the Senior Notes by the Company's subsidiaries. On November 12, 2013, the Company filed a registration statement on Form S-3 with the SEC, which allows for automatic registration for well-known seasoned issuers. As of December 31, 2013, all of the existing subsidiaries of the Company are guarantors of the 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.

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 7 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 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

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

	Office Leases
2014	$ 2,349,477
2015	2,359,221
2016	2,373,367
2017	2,438,465
2018 and thereafter	7,350,522
	$ 16,871,052

The Company's office leases extend through 2021. Rent expense for the years ended December 31 2013, 2012, and 2011 was $1.4 million, $886,000, and $487,000, respectively

NOTE 8 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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8 STOCK-BASED COMPENSATION (Continued)

were granted were valued at the IPO stated price of $17.00 per share and vest over a three-year period. Stock-based compensation expense of $2.5 million, $2.5 million, and $122,000 was recorded during the years ended December 31, 2013, 2012, and 2011, respectively. As of December 31, 2013 there was $2.3 million of unrecognized compensation costs related to the unvested restricted common stock granted under the plan, which is to be amortized through 2014.

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, 59,372 previously issued shares of our common stock that were fully vested and held by the BCEC Investment Trust were distributed to certain 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.

BCEC Management Incentive Plan

In connection with the corporate restructuring, 317,142 shares of common stock of BCEI were designated for holders of Bonanza Creek Energy, LLC's, our predecessor, Class B units. These shares were held in trust for the benefit of employees. On December 15, 2011, 243,945 of these shares were valued at $17.00 per share and granted to employees without vesting requirements and the Company recorded a stock-based compensation charge in the amount of $4,147,000.

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.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8 STOCK-BASED COMPENSATION (Continued)

During 2013, the Company granted 292,396 shares of restricted stock under the LTIP to certain employees. The fair value of the issuance was $12.4 million. The Company recognized compensation expense of $2.6 million for the year ended December 31, 2013. As of December 31, 2013 unrecognized compensation cost was $9.6 million and will be amortized through 2016.

During 2012, the Company granted 697,500 shares of restricted common stock under the LTIP to certain employees. The fair value of the issuance was $11.8 million. The Company recognized compensation expense of $4.3 million and $1.7 million for the years ended December 31, 2013 and 2012, respectively. As of December 31, 2013 unrecognized compensation cost was $5.3 million and will be amortized through 2015.

In 2013 and 2012, the Company issued 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 $445,000 and $267,000 for the years ended December 31, 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,					
	2013		2012		2011	
	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	929,336	$ 17.06	437,787	$ 17.00		$
Granted	310,439	$ 39.89	731,034	$ 16.98	437,787	$ 17.00
Vested	(371,956)	$ 17.44	(159,147)	$ 17.11		$
Forfeited	(31,817)	$ 24.09	(80,338)	$ 15.89		$
Non-vested at end of year	836,002	$ 25.11	929,336	$ 17.06	437,787	$ 17.00

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 $127,830 for the year ended December 31, 2013 as cash inflows from financing activities. The Company recorded no excess tax benefits for the years ended December 31, 2012 and 2011.

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 and is determined based on the Company's performance over a three-year measurement period. 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. Expense associated with PSUs is recognized as general and administrative expense over the measurement period. The PSUs vest in their entirety at the end of the measurement period.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8 STOCK-BASED COMPENSATION (Continued)

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 three-year 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 a three year measurement period, as well as the volatilities for each of the Company's peers.

During 2013, the Company granted 41,622 PSUs under the LTIP to certain officers. The Company recognized compensation expense of $340,000 for the year ended December 31, 2013. As of December 31, 2013, unrecognized compensation expense for PSUs was $1 million and is being amortized through 2015. The fair value of the PSUs granted in 2013 was $1.2 million.

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

	For the Year Ended December 31, 2013	
	PSU	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year(1)		$
Granted(1)	41,622	$ 32.01
Vested(1)		$
Forfeited(1)	(1,431)	$ 30.85
Non-vested at end of year(1)	40,191	$ 32.05

(1) The number of awards assumes a one multiplier. The final number of shares of common stock issued may vary depending on the ending three-year performance multiplier, which ranges from zero to two.

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 $837,000, $589,000, and $296,000 for the years ended December 31, 2013, 2012, and 2011, respectively.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 9 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,		
	2013	**2012**	**2011**
Current tax expense			
Federal	$ 121,926	$ 288,659	$
State	126,010	243,114	
Deferred tax expense	42,432,114	30,772,973	11,198,240
Total income tax expense	$ 42,680,050	$ 31,304,746	$ 11,198,240

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,	
	2013	**2012**
Deferred tax liabilities:		
Oil and gas properties	$ 195,775,731	$ 132,932,511
Total deferred tax liabilities	195,775,731	132,932,511
Deferred tax assets:		
Federal and state tax net operating loss carryforward	31,289,282	16,061,072
Reclamation costs	4,310,643	2,981,012
Stock compensation	2,617,119	777,069
Derivative liability	1,832,642	1,398,054
AMT credit	776,197	446,683
State bonus depreciation addback	1,937,672	791,793
Other long-term liabilities	331,284	100,222
Total deferred tax assets	43,094,839	22,555,905
Total non-current net deferred tax liability	$ 152,680,892	$ 110,376,606

The Company has $95,053,000 and $43,806,000 of net operating loss carryovers for federal income tax purposes of which $9,311,000 and $444,000 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, 2013 and 2012, respectively. 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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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 9 INCOME TAXES (Continued)

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,		
	2013	**2012**	**2011**
Federal statutory tax expense	39,152,349	27,173,985	8,122,403
Increase (decrease) in tax resulting from:			
State tax expense net of federal benefit	3,833,606	2,753,365	950,926
Rate change and other	(305,905)	1,377,396	2,124,911
Total income tax expense	$ 42,680,050	$ 31,304,746	$ 11,198,240

Reconciliation of the Company's effective tax rate to the expected federal tax rate of 35%, 35%, and 34% in 2013, 2012, and 2011 is as follows:

	For the Years Ended December 31,		
	2013	**2012**	**2011**
Expected federal tax rate	35%	35%	34%
State income taxes	3.43%	3.55%	3.98%
Change in tax rate	-0.28%	1.67%	8.90%
Effective tax rate	38.15%	40.22%	46.88%

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 our consolidated statements of operations and comprehensive income is $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 our consolidated statements of operations and comprehensive income of $30.8 million.

During the year ended December 31, 2011, the estimated tax rate was revised to reflect significant capital expenditures in Arkansas and the effective tax rate increased from 36.87% to 37.98%. The increase in the effective tax rate was applied to the January 1, 2011 deferred income tax liability resulting in an increase to the net deferred tax liability and deferred income tax expense of $2.1 million with an additional $9.1 million incurred for federal and state income taxes for the year ended December 31, 2011, which together resulted in a total deferred income tax expense in our consolidated statements of operations and comprehensive income of $11.2 million.

The Company had no unrecognized tax benefits as of December 31, 2013, 2012, and 2011.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 10 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 discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred and has been set at 8%. 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 revisions to estimate for the year ended December 31, 2013 is comprised of increased abandonment cost on wells that had an asset retirement obligation as of the beginning of the year.

	As of December 31,	
	2013	**2012**
Beginning of year	$ 7,333,584	$ 6,039,723
Additional liabilities incurred	1,066,822	1,448,063
Accretion expense	645,360	519,315
Obligations on properties sold		(511,730)
Liabilities settled	(73,358)	(161,787)
Revisions to estimate	2,077,624	
End of year	$ 11,050,032	$ 7,333,584

NOTE 11 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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11 FAIR VALUE MEASUREMENTS (Continued)

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 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.

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, 2013 and 2012 and their classification within the fair value hierarchy:

	As of December 31, 2013		
	Level 1	**Level 2**	**Level 3**
Derivative assets	$	$ 735,690	$ 414,864
Derivative liabilities	$	$ 1,740,824	$ 4,782,177

	As of December 31, 2012		
	Level 1	**Level 2**	**Level 3**
Derivative assets	$	$ 450,872	$ 1,727,192
Derivative liabilities	$	$ 5,173,140	$ 1,235,168

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 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. The Company's collars, which are designated as Level 3 within the valuation hierarchy, are not validated by observable transactions with respect to volatility. Presently, all of our derivative arrangements are concentrated with five counterparties all of which are lenders under the Company's Revolver.

For the oil and natural gas derivatives outstanding at December 31, 2013, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2013 would change our derivative gain (loss) by $42.7 million and $(34.1) million, respectively.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11 FAIR VALUE MEASUREMENTS (Continued)

The following table reflects the activity for the commodity derivatives measured at fair value using Level 3 inputs for the year ended December 31, 2013:

	For the Year Ended December 31, 2013	
	Derivative Asset	Derivative Liability
Beginning balance	$ 1,727,192	$ 1,235,168
Net increase (decrease) in fair value(1)	(3,931,350)	(416,705)
Net settlement(1)	(586,249)	1,718,696
New derivatives	3,205,271	2,245,018
Transfers in (out) of Level 3		
Ending balance	$ 414,864	$ 4,782,177

(1) Net increase (decrease) in fair value and net settlements are shown in the derivative gain (loss) line item of the accompanying statements of operations and comprehensive income.

The following table reflects the activity for the commodity derivatives measured at fair value using Level 3 inputs for the year ended December 31, 2012:

	For the Year Ended December 31, 2012	
	Derivative Asset	Derivative Liability
Beginning balance	$ 881,822	$ 1,115,595
Net increase (decrease) in fair value(1)	796,287	(3,239,647)
Net settlement(1)	(362,095)	527,766
New derivatives	411,178	2,831,454
Transfers in (out) of Level 3		
Ending balance	$ 1,727,192	$ 1,235,168

(1) Net increase (decrease) in fair value and net settlements are shown in the derivative gain (loss) line item of the accompanying statements of operations and comprehensive income.

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 discount rates and price forecasts selected by the Company's management. The calculation of the discount rate is a significant management estimate based on the best information available and estimated to be 10% for the year ended December 31, 2013. Management believes that the discount rate is representative of current market conditions and reflects the following factors: estimate 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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11 FAIR VALUE MEASUREMENTS (Continued)

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. There were no proved properties measured at fair value at December 31, 2013 and 2012.

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 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 use 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, 2013 and 2012.

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. There were no asset retirement obligations measured at fair value at December 31, 2013 and 2012.

Long-term Debt

The Senior Notes are recorded at cost net of the unamortized premium on the accompanying balance sheets at $508.8 million. The fair value of the Senior Notes as of December 31, 2013 was $527.5 million measured using Level 1 inputs based on a secondary market trading price. The carrying value of the Company's credit facility approximates fair value, as the applicable interest rates are floating.

NOTE 12 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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 12 DERIVATIVES (Continued)

agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar agreements, the Company receives the difference between an agreed upon index and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

As of December 31, 2013, 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	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability)
Oil							
1Q 2014	Swap	3,133	$ 96.97				$ (403,499)
2Q 2014	Swap	4,126	$ 96.20				(288,370)
3Q 2014	Swap	3,870	$ 93.04				(518,444)
4Q 2014	Swap	3,870	$ 93.04				205,179
1Q 2014	Collar	5,617			$ 86.33	$ 97.09	(1,338,410)
2Q 2014	Collar	4,846			$ 86.55	$ 96.72	(1,252,787)
3Q 2014	Collar	4,326			$ 86.16	$ 96.57	(615,971)
4Q 2014	Collar	4,326			$ 86.16	$ 96.57	(68,724)
2014	3-Way Collar	1,000		$ 60.00	$ 85.00	$ 99.50	(303,314)
2015	3-Way Collar	4,500		$ 66.67	$ 83.33	$ 94.12	(782,385)
							$ (5,366,725)
Gas							
2014	3-Way Collar	15,000		$ 3.50	$ 4.00	$ 4.75	$ 122,173
2015	3-Way Collar	15,000		$ 3.50	$ 4.00	$ 4.75	(127,895)
							$ (5,722)
Total							$ (5,372,447)

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 12 DERIVATIVES (Continued)

As of the date of filing 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	Average Floor Price	Average Ceiling Price
Oil						
1Q 2014	Swap	3,133	$ 96.97			
2Q 2014	Swap	4,126	$ 96.20			
3Q 2014	Swap	3,870	$ 93.04			
4Q 2014	Swap	3,870	$ 93.04			
1Q 2014	Collar	5,617			$ 86.33	$ 97.09
2Q 2014	Collar	4,846			$ 86.55	$ 96.72
3Q 2014	Collar	4,326			$ 86.16	$ 96.57
4Q 2014	Collar	4,326			$ 86.16	$ 96.57
1Q 2014	3-Way collar	1,000		$ 60.00	$ 85.00	$ 99.50
2Q - 4Q 2014	3-Way Collar	2,000		$ 65.00	$ 87.68	$ 99.75
2015	3-Way Collar	4,500		$ 66.67	$ 83.33	$ 94.12
Gas						
1Q 2014	3-Way Collar	22,500		$ 3.56	$ 4.13	$ 4.78
2Q - 4Q 2014	3-Way Collar	30,000		$ 3.63	$ 4.21	$ 4.81
2015	3-Way Collar	15,000		$ 3.50	$ 4.00	$ 4.75

Derivative Assets and Liabilities Fair Value

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, 2013 and 2012:

	As of December 31, 2013	
	Balance Sheet Location	**Fair Value**
Derivative Assets		
Commodity contracts	Current assets	$ 857,863
Commodity contracts	Noncurrent assets	292,691
Derivative Liabilities		
Commodity contracts	Current liabilities	(5,320,030)
Commodity contracts	Long-term liabilities	(1,202,971)
Total net derivative liability		$ (5,372,447)

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 12 DERIVATIVES (Continued)

	As of December 31, 2012	
	Balance Sheet Location	**Fair Value**
Derivative Assets		
Commodity contracts	Current assets	$ 2,178,064
Commodity contracts	Noncurrent assets	
Derivative Liabilities		
Commodity contracts	Current liabilities	(5,200,202)
Commodity contracts	Long-term liabilities	(1,208,106)
Total net derivative liability		$ (4,230,244)

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

	For the Years Ended December 31,		
	2013	**2012**	**2011**
Derivative cash settlement gain (loss):			
Oil contracts	$ (11,755,140)	$ (1,491,948)	$ (3,694,974)
Gas contracts	425,291	766,566	670,838
Total derivative cash settlement (loss)(1)	$ (11,329,849)	$ (725,382)	$ (3,024,136)
Change in fair value gain (loss):			
Oil contracts	$ (1,142,203)	$ 1,649,687	$ 225,393
Gas contracts			
Total change in fair value gain (loss)	$ (1,142,203)	$ 1,649,687	$ 225,393
Total derivative gain (loss)(2)	$ (12,472,052)	$ 924,305	$ (2,798,743)

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

NOTE 13 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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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 13 EARNINGS PER SHARE (Continued)

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, 2013, 2012, and 2011:

	For the Years Ended December 31,		
	2013	2012	2011
Income from continuing operations:			
Income from continuing operations	$ 69,581,803	$ 44,570,601	$ 14,608,857
Less: undistributed earnings to unvested restricted stock	1,672,809	825,295	214,892
Undistributed earnings to common shareholders	67,908,994	43,745,306	14,393,965
Basic income per common share from continuing operations	$ 1.73	$ 1.12	$ 0.49
Diluted income per common share from continuing operations	$ 1.72	$ 1.12	$ 0.49
Income (loss) from discontinued operations:			
Income (loss) from discontinued operations	$ (398,000)	$ 1,951,976	$ (1,917,676)
Less: undistributed earnings to unvested restricted stock	(9,568)	36,144	(28,208)
Undistributed earnings to common shareholders	(388,432)	1,915,832	(1,889,468)
Basic income (loss) per common share from discontinued operations	$ (0.01)	$ 0.05	$ (0.06)
Diluted income (loss) per common share from discontinued operations	$ (0.01)	$ 0.05	$ (0.06)
Net income:			
Net income	$ 69,183,803	$ 46,522,577	$ 12,691,181
Less: undistributed earnings to unvested restricted stock	1,663,240	861,439	186,683
Undistributed earnings to common shareholders	67,520,563	45,661,138	12,504,498
Basic net income per common share	$ 1.72	$ 1.17	$ 0.43
Diluted net income per common share	$ 1.71	$ 1.17	$ 0.43
Weighted-average shares outstanding basic	39,337,121	39,051,739	29,323,999
Add: dilutive effect of contingent PSUs	66,478		
Weighted-average shares outstanding diluted	39,403,599	39,051,739	29,323,999

The Company had no anti-dilutive shares for the years ended December 31, 2013, 2012, and 2011.

During 2013, the Company determined that the issued shares of restricted stock are in fact participating securities and have applied the two-class method. The application of the two-class method had no impact to the previously reported per share amounts.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 14 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,		
	2013	2012	2011
Acquisition(1)	$ 13,797,175	$ 58,843,099	$ 1,894,300
Development(2)(3)	452,454,489	341,135,387	109,231,551
Exploration	2,590,416	4,821,190	58,034,514
Total(4)	$ 468,842,080	$ 404,799,676	$ 169,160,365

(1) Acquisition costs for unproved properties for the years ended December 31, 2013, 2012, and 2011 were $3,412,708, $57,048,277, and $1,131,599, respectively. Acquisition costs for proved properties for the years ended December 31, 2013, 2012, and 2011 were $10,384,467, $1,794,822, and $761,701, respectively.

(2) Development costs include workover costs of $5,955,397, $4,463,344 and $2,808,663 charged to lease operating expense during 2013, 2012, and 2011, respectively.

(3) Development costs include gas plant capital expenditures of $4,288,886, $16,177,371, and $25,069,757 for the years ended December 31, 2013, 2012, and 2011, respectively.

(4) Includes amounts relating to ARO of $3,144,446, $1,448,063, and $139,771 for the years ended December 31, 2013, 2012, and 2011, respectively.

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

	For the Years Ended December 31,		
	2013	2012	2011
Beginning balance at January 1	$	$ 5,438,303	$ 974,000
Additions to capitalized exploratory well costs pending the determination of proved reserves		2,940,309	7,075,921
Reclassifications to wells, facilities and equipment based on the determination of proved reserves			(2,611,618)
Capitalized exploratory well costs charged to expense		(8,378,612)	
Ending balance at December 31	$	$	$ 5,438,303

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 the year. During the year ended December 31, 2012, the Company incurred $8,378,612 of dry hole expense.

NOTE 15 DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The proved reserve estimates at December 31, 2013 are based on reports prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineers, whereas the December 31, 2012 and 2011 estimated proved reserved were prepared by Cawley, Gillespie & Associates, Inc. The estimates of

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 15 DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) (Continued)

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.

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, 2013, 2012, and 2011 are as follows:

	Oil (MBbl)(1)	Natural Gas (MMcf)
Balance December 31, 2010	22,379	62,884
Extensions and discoveries(2)	7,182	29,608
Sales of minerals in place		
Production	(1,137)	(2,776)
Purchases of minerals in place		
Revisions to previous estimates(3)	(208)	3,266
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
Proved developed reserves:		
December 31, 2011	11,842	31,313

December 31, 2012	15,675	48,942
December 31, 2013	22,273	59,250
Proved undeveloped reserves:		
December 31, 2011	16,374	61,669
December 31, 2012	17,591	69,606
December 31, 2013	24,209	80,364

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 15 DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) (Continued)

(2)

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 are 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.

At December 31, 2011, extensions and discoveries of 12,117 MBoe resulted from our capital program in the Wattenberg Field, Rocky Mountain Region. The capital program consisted of both vertical and horizontal drilling in the Codell and Niobrara formations.

(3)

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.

At December 31, 2011, we revised our proved reserves upward by 336 MBoe. This positive revision is primarily the result of an increase in oil price of $16.76 per Bbl WTI from $79.43 per Bbl at December 31, 2010 to $96.19 per Bbl at December 31, 2011. This positive revision was partially offset by small negative performance revisions in the Dorcheat Macedonia Field, Mid-Continent Region and in the vertical producers in the Wattenberg Field, Rocky Mountain Region due to surface pressure limitations.

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 15 DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) (Continued)

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.

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

	For the Years Ended December 31,		
	2013	2012	2011
Future cash flows	$ 4,799,149	$ 3,367,465	$ 2,887,010
Future production costs	(1,681,419)	(1,037,537)	(805,466)
Future development costs	(776,512)	(684,160)	(514,256)
Future income tax expense	(576,024)	(298,201)	(252,265)
Future net cash flows	1,765,194	1,347,567	1,315,023
10% annual discount for estimated timing of cash flows	(839,911)	(664,126)	(648,837)
Standardized measure of discounted future net cash flows	$ 925,283	$ 683,441	$ 666,186

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

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 15 DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) (Continued)

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

	For the Years Ended December 31,		
	2013	**2012**	**2011**
Beginning of period	$ 683,441	$ 666,186	$ 374,654
Sale of oil and gas produced, net of production costs	(346,679)	(189,840)	(84,888)
Net changes in prices and production costs	94,881	(81,527)	123,154
Extensions, discoveries and improved recoveries	571,384	310,595	204,000
Development costs incurred	67,063	161,527	93,916
Changes in estimated development cost	127,034	(9,404)	(62,175)
Purchases of mineral in place	5,442		
Sales of mineral in place		(14,909)	
Revisions of previous quantity estimates	(212,034)	(156,867)	8,113
Net change in income taxes	(150,704)	(23,441)	(40,866)
Accretion of discount	83,468	79,398	46,158
Changes in production rates and other	1,987	(58,277)	4,120
End of period	$ 925,283	$ 683,441	$ 666,186

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2013, 2012, and 2011 were calculated using the twelve-month arithmetic average of first-day-of-the-month price inclusive of adjustments for quality and location.

	2013	**2012**	**2011**
Oil (per Bbl)	$ 92.03	$ 91.04	$ 89.80
Gas (per Mcf)	$ 4.67	$ 3.78	$ 4.82

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 16 QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2013 and 2012:

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2013				
Oil and gas sales(2)	$ 78,307,013	$ 84,517,472	$ 125,973,199	$ 133,062,418
Operating profit(1)(2)	39,000,509	36,750,600	68,180,143	62,779,799
Net income	11,255,816	14,714,908	17,781,421	25,431,658
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
2012				
Oil and gas sales(2)	$ 47,830,431	$ 51,455,094	$ 58,327,823	$ 73,591,893
Operating profit(1)(2)	26,126,248	28,696,782	29,145,797	36,665,466
Net income	8,546,153	21,506,103	3,420,887	13,049,434
Basic and diluted net income per common share	$ 0.22	$ 0.54	$ 0.09	$ 0.32

(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, 2013 and 2012.

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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, 2013. 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, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2013, 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.

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, 2013, 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 1992. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2013, 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, 2013, which is included in the consolidated financial statements in Item 8, Part II of this Annual Report on Form 10-K.

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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, 2013 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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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, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. 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 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, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992.

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, 2013 and 2012, 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, 2013, and our report dated February 28, 2014 expressed an unqualified opinion.

/s/ Hein & Associates LLP

Denver, Colorado
February 28, 2014

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Item 9B. ***Other Information*****.**

None.

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 2014 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2013.

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 "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 Department, 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 2014 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2013.

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 2014 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2013.

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 2014 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2013.

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 2014 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2013.

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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 on February 28, 2014.

BONANZA CREEK ENERGY, INC.

By: /s/ MARVIN M. CHRONISTER

Marvin M. Chronister,
Interim President and Chief Executive Officer
(principal executive officer)

February 28, 2014

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Marvin M. Chronister, William J. Cassidy, 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.

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.

Date: February 28, 2014	By:	/s/ MARVIN M. CHRONISTER Marvin M. Chronister, *Interim President and Chief Executive Officer (principal executive officer)*
Date: February 28, 2014	By:	/s/ WILLIAM J. CASSIDY William J. Cassidy, *Executive Vice President and Chief Financial Officer (principal financial officer)*
Date: February 28, 2014	By:	/s/ WADE E. JAQUES Wade E. Jaques, *Vice President, Chief Accounting Officer, and Treasurer (principal accounting officer)*

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Date: February 28, 2014	By:	/s/ RICHARD J. CARTY
		Richard J. Carty, *Chairman of the Board*
Date: February 28, 2014	By:	/s/ GARY A. GROVE
		Gary A. Grove, *Director, Executive Vice President Engineering and Planning*
Date: February 28, 2014	By:	/s/ KEVIN A. NEVEU
		Kevin A. Neveu, *Director*
Date: February 28, 2014	By:	/s/ GREGORY P. RAIH
		Gregory P. Raih, *Director*
Date: February 28, 2014	By:	/s/ JAMES A. WATT
		James A. Watt, *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)
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	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 10.1 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)
10.7	Amendment No. 5 & Agreement, 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)

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Exhibit Number	Description
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	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)
10.12	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)
10.13*	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)
10.14*	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)
10.15*	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)
10.16	Form of Performance Share Agreement (incorporated by reference to Exhibit 10.3 of the Current Report on Form 8-K filed on March 29, 2013)
10.17*	Employment Letter Agreement effective April 29, 2013 between Bonanza Creek Energy, Inc. and Michael R. Starzer (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on May 3, 2013)
10.18*	Employment Letter Agreement effective April 29, 2013 between Bonanza Creek Energy, Inc. and Gary A. Grove (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on May 3, 2013)
10.19*	Employment Letter Agreement effective April 29, 2013 between Bonanza Creek Energy, Inc. and Patrick A. Graham (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed on May 3, 2013)
10.20*	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)
10.21*	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)
10.22*	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)

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Exhibit Number	Description
10.23	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)
10.24*	Bonanza Creek Energy, Inc. Executive Change in Control and Severance Plan, as amended (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed on May 3, 2013)
10.25*	Bonanza Creek Energy, Inc. Short Term Incentive Guidelines (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed on May 10, 2013)
10.26	Contribution Agreement, dated as of December 23, 2010, among Bonanza Creek Energy, Inc., Bonanza Creek Energy Company, LLC, Bonanza Creek Energy Operating Company, LLC, Bonanza Creek Energy Resources, LLC and members of Holmes Eastern Company, LLC (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1/A filed on July 25, 2011)
10.27	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)
10.28	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 4.2 of the Current Report on Form 8-K filed on April 11, 2013)
10.29	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)
10.30	Underwriting Agreement, dated January 31, 2013, among Bonanza Creek Energy, Inc. and Project Black Bear LP and Credit Suisse Securities (USA) LLC and Raymond James & Associates, Inc., as representatives of the several underwriters listed therein (incorporated by reference to Exhibit 1.1 of the Current Report on Form 8-K filed on February 4, 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)
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)

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Exhibit Number	Description
99.1	Report of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc. for reserves as of December 31, 2013
101	The following material from the Bonanza Creek Energy, Inc Annual Report on Form 10-K for the year ended December 31, 2013 (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. The information in Exhibit 101 is "furnished" and not "filed", as provided in Rule 402 pf Regulation S-T

*

Management Contract or Compensatory Plan or Arrangement

Filed or furnished herewith