Bonanza Creek Energy, Inc.
Form 10-K
March 15, 2013

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Item 8. Financial Statements and Supplementary Data.

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UNITED STATES
SECURITIES AND EXCHANGE 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, 2012

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. o

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 o	Accelerated filer ý	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 29, 2012, based upon the closing price of $16.63 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $138,010,440. Excludes approximately 31,713,010 million shares of the registrant's common stock held by current executive officers, directors and stockholders that the registrant has concluded are affiliates of the registrant.

Number of shares of registrant's common stock outstanding as of February 28, 2013: 40,040,430

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2013 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, are incorporated by reference into Part III of this report for the year ended December 31, 2012.

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BONANZA CREEK ENERGY, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2012

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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" 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 2013;
- 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;
- compliance with debt covenants;
- ability to satisfy obligations related to ongoing operations;
- compliance with government regulations;
- impact from the lack of available gathering systems and processing facilities;
- 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;
- loss of any purchaser of the our products;
- our estimated revenues and losses;

- the timing and success of specific projects;
- 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;
- 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

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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 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 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 retain key members of our senior management and key technical employees;

ability to maintain effective internal controls;

access to adequate gathering systems and pipeline take-away capacity to execute 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.

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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.

"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.

"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,

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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" A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"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.

"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 feature.

"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.

"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.

"Original oil in place" Refers to the oil in place before the commencement of production. Oil in place is distinct from oil reserves, which are the technically and economically recoverable portion of oil volume in the reservoir.

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

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

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

"Possible reserves" Those reserves that are less certain to be recovered than probable reserves.

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

"Production Costs" Production costs are the costs of activities that involve lifting oil and natural gas to the surface and gathering, treating, processing, and storage in the field.

"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.

The area of the reservoir considered as proved includes:

(i) The area identified by drilling and limited by fluid contacts, if any, and

(ii) 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.

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:

(i) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

(ii) The project has been approved for development by all necessary parties and entities, including governmental entities.

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 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.

"Spacing" The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies. 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.*

Overview

Bonanza Creek Energy, Inc. ("Bonanza Creek" or, together with our consolidated subsidiaries, the "Company," "we," "us," or "our") 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 (Rocky Mountain region) and the Dorcheat Macedonia Field in southern Arkansas (Mid-Continent region). In addition, we own and operate oil-producing assets in the North Park Basin in Colorado and one non-core Field in California. 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 99.3% of our proved reserves with an average working interest of 87.3%, providing us with significant control over the rate of development of our asset base.

As of December 31, 2012, we accumulated 79,843 gross (69,184 net) leasehold acres across our properties. We are currently focused on the horizontal development of significant resource potential from the Niobrara and Codell formations in the Wattenberg Field, investing approximately 82% of our 2013 capital budget in this project. The remaining 18% of our 2013 budget is allocated primarily to the vertical development of the Dorcheat Macedonia Field in southern Arkansas, targeting the oily Cotton Valley sands. We also plan to drill development wells in the McKamie Patton Field and finalize an expansion of our gas processing facilities in Arkansas. 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 2012, we drilled 150 operated wells and 9 non-operated wells and had 4 development wells in progress as of December 31, 2012. The resulting production rates achieved by this program increased sales volumes by 115% over the previous year to 9,403 Boe/d of which 73% was crude oil and natural gas liquids. The Rocky Mountain region contributed 49% and the Mid-Continent region contributed 50% to total production, while California was responsible for 1%. Our average net daily production rate during December 2012 was 12,468 Boe/d, a 105% increase over December 2011.

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.

Cawley, Gillespie & Associates, Inc., our independent reserve engineers, estimated our net proved reserves as of December 31, 2012, to be as follows:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed				
Rocky Mountain	8,365	31,646		13,639
Mid-Continent	5,934	17,296	1,345	10,162
California	31			31
Undeveloped				
Rocky Mountain	10,847	47,692		18,796
Mid-Continent	4,982	21,914	1,762	10,396
California				
Total Proved	30,159	118,548	3,107	53,024

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	Estimated Proved Reserves at December 31, 2012(1)				Production for the Year Ended December 31, 2012			
	Total Proved (MBoe)	% of Total	% Proved Developed	PV-10 ($ in MM)(2)	Average Net Daily Production (Boe/d)	% of Total	Projected 2013 Capital Expenditures ($ in millions)	Net Proved Undeveloped Drilling Locations as of December 31, 2012
Rocky Mountain	32,435	61%	42%	$ 450.2	4,568	49%	324	144.6
Mid-Continent	20,558	39%	49%	383.9	4,689	50%	70	99.9
California	31	0%	100%	0.6	146	1%	0	0
Total	53,024	100%	45%	$ 834.7	9,403	100%	394	244.5

(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 $94.71 per Bbl WTI and $2.757 per MMBtu of HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $3.67 per Bbl of crude oil and an increase of $1.02 per MMBtu of natural gas respectively.

(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 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. We believe that PV-10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV-10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts and sophisticated investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating the Company and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves. PV-10 differs from Standarized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. See " Reconciliation of PV-10 to Standardized Measure" 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 ("Black Bear"), 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." For more information, see Note 1 to our consolidated financial statements in Item 8 of Part II of this Annual Report on Form 10-K. 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.

Acquisition

On August 1, 2012, we leased approximately 5,600 net acres from the State of Colorado in the core of our Wattenberg Field position for a total purchase price of approximately $57 million, of which

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$12 million was payable at closing and the balance is payable in equal annual lease payments over the next four years. This development will be facilitated by the Company's existing relationships with surface landowners allowing for efficiencies in future development.

Our Business Strategies

Our goal is to increase stockholder value by investing capital to increase our production, proved reserves and cash flow. We intend to accomplish this by focusing on the following key strategies:

Increase Production from Existing Unconventional Resource Inventory. We intend to develop the Niobrara and Codell formations utilizing the horizontal drilling for our inventory in the Wattenberg Field. During 2012, we transitioned to drilling primarily horizontal wells in the Wattenberg, focusing on the prolific Niobrara "B" Bench, primarily using 4,000 foot laterals.

Enhance Recoveries and Develop Additional Resource Potential in Our Core Project Areas. We are testing and currently evaluating the application of 9,000 foot laterals, known as extended reach laterals, in the Niobrara "B" Bench and horizontal drilling in the Niobrara "C" Bench and Codell formation in the Wattenberg Field. In addition, we believe that the potential to downspace wells in the Niobrara to 40 acres and in the Dorcheat-Macedonia Field in Arkansas to five acres, presents an opportunity to significantly expand our inventory.

Pursue Accretive Acquisitions. We intend to pursue bolt-on acquisitions in the Wattenberg Field and in southern Arkansas, similar to our August 2012 lease acquisition from the State of Colorado, where we can take advantage of our operational scale and local knowledge. In addition, we will evaluate unconventional oil and liquids-rich opportunities where we believe the application of our core competencies of horizontal drilling and fracture stimulation will enhance the value and performance of the acquired properties.

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.

Our Competitive Strengths

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

Niobrara and Codell Resource Development. We have accumulated approximately 31,000 net acres in the extension area of the Wattenberg Field prospective for the Niobrara formation and approximately 15,000 acres for the Codell formation. Our acreage is in an area noted for its net high oil and liquids content and strong economic returns. We believe our acreage position represents significant production, reserve and value growth potential and that the consistently positive results in this play by us and other operators validates our investment and will result in the continued development of the area. Geologic risks associated with our Wattenberg Field acreage position have been mitigated by the high volume of data provided through the drilling, completion and production of thousands of vertical wells and now hundreds of horizontal wells in the Niobrara in close proximity to and within our acreage. We have 3-D seismic surveys covering approximately 35,000 acres located across our properties in the Wattenberg Field. Adequate gathering systems and takeaway capacity are in place, enabling a short time period from well completion to first product sales and relatively strong pricing.

High Degree of Operational Control. We hold an average working interest of approximately 87.3% and operate approximately 99.3% of our proved reserves, which 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.

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Gas Processing Capability in Southern Arkansas. The processing of our natural gas at our McKamie and Dorcheat facilities improves our development 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, 2012 was approximately $123.3 million, comprised of $119 million of availability under our credit facility and approximately $4.3 million of cash on hand.

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.

We believe the Wattenberg Field to be the most prospective area for the Niobrara formation evidenced by, to date, a high level of industry activity and successful drilling results.

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, 2012, our Wattenberg position consisted of approximately 33,000 gross (31,000 net) acres. During 2012, we had a net increase of approximately 1,500 net acres in the Wattenberg Field, which includes an increase in net acreage of approximately 6,000 acres through acquisitions and leasing in our core area and a reduction of approximately 4,500 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.

The Wattenberg Field is now primarily developed for the Niobrara and Codell formations using horizontal drilling and multi-stage fracture stimulation techniques. We are developing the Niobrara "B" Bench at 80-acre spacing while testing the Niobrara "C" bench and further down spacing. We have also begun testing the Codell formation, which is prospective on approximately 15,000 of our net acres.

Our estimated proved reserves at December 31, 2012 in the Wattenberg Field were 31,943 MBoe. As of December 31, 2012, we had a total of 266 producing wells, of which 46 were horizontal wells, and our average daily production during 2012 was approximately 4,385 Boe/d, of which 51% came from horizontal wells. Our average daily production for the month of December 2012 was 7,133 Boe/d. Our working interest for all producing wells averages approximately 93% and our net revenue interest is approximately 77%.

We continue to expand our proved reserves in this area by drilling non-proved horizontal locations. During 2012, we drilled 35 horizontal wells and 72 vertical wells. We estimate our capital expenditures in the Wattenberg Field for 2013 will be $324 million, which includes drilling 64 horizontal wells in the

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Niobrara "B" Bench, four horizontal wells in the Niobrara "C" Bench and four horizontal wells in the Codell sandstone. This drilling program includes 12 proved locations and 60 non-proved locations.

Our horizontal well program delivered strong production performance in 2012. We drilled 32 4,000 foot horizontal wells in the Niobrara "B" Bench at an average well cost of $4.5 million. Of these wells, 26 produced for longer than 30 days for an average 30-day initial production rate of 514 Boe/d at 76% crude oil, while 21 wells produced for longer than 60 days for an average 60-day production rate of 395 Boe/d at 74% crude oil. We drilled one horizontal well in the Codell formation for approximately $4.5 million, which had a 30-day average production rate of 370 Boe/d at 81% crude oil, and one horizontal well in the Niobrara "C" Bench for approximately $4.4 million, which delivered a 30-day average production rate of 444 Boe/d at 79% crude oil. Our extended reach lateral into the Niobrara "B" Bench was drilled in 2012 and cost approximately $7.4 million. This well began producing in 2013 and had a 30-day average production rate of 795 Boe/d at 76% crude oil.

North Park Basin Jackson County, Colorado. We control approximately 30,397 gross (24,605 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, 2012 were approximately 492 MBoe, 100% of which were crude oil. Our average net production during 2012 was approximately 114 Boe/d. None of our CO_2 production is currently reflected in our reserve reports. During 2012, we re-entered and deepened one vertical well, classified as a non-proved location.

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 not allocated any development or exploration capital to this area in 2013.

Mid-Continent Region

In southern Arkansas, we target the oil-bearing Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton Fields. As of December 31, 2012, our estimated proved reserves in this region were 20,558 MBoe, 68% of which were oil and natural gas liquids and 49% of which were proved developed. We currently operate 186 producing wells and, as of December 31, 2012, have an identified drilling inventory of approximately 122 gross (99.9 net) PUD drilling locations on our acreage. During 2012, we drilled 42 wells in the Dorcheat Macedonia and McKamie Patton Fields. We achieved an average production rate for 2012 of 4,689 Boe/d, of which 71% was from crude oil and liquids, and an average production rate for December 2012 of 5,285 Boe/d.

Dorcheat Macedonia. In the Dorcheat Macedonia Field, we average an 82% working interest and 68% net revenue interest on all producing wells, and all of our acreage is held by production. We have approximately 152 producing wells and our average net daily production during 2012 was approximately 4,289 Boe/d. During the month of December 2012, it was approximately 4,289 Boe/d. Our proved reserves in this Field are booked at 10-acre spacing and are approximately 18,948 MBoe. 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.

Historically, the Dorcheat Macedonia Field reservoirs have responded favorably to fracture stimulation. Beginning in the fourth quarter of 2009, we began to implement pinpoint fracture stimulation utilizing coiled tubing. Post-fracture treatment tracer work has confirmed that pinpoint fracture placement provides much better coverage and penetration of the intended producing intervals.

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Results from wells employing this technique have seen initial production rates higher than historic rates and show stimulation of previously unstimulated zones.

As of December 31, 2012, we have identified approximately 120 gross (97.9 net) PUD drilling locations on our acreage in this area. During 2012, we drilled 38 vertical Cotton Valley wells in Dorcheat-Macedonia. We have budgeted capital expenditures for 2013 of approximately $61.6 million for the development of this Field. In 2013, we expect to drill 30 PUD locations with a complete cost per well of approximately $1.8 million, approximately $1.7 million of which will be for initial drilling and completion. In addition, we plan to drill three wells testing our second 5-acre downspacing pilot. If successful, this program has the potential to significantly expand our drilling inventory in the Field.

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, 2012, our estimated aggregate proved reserves in these Fields were approximately 1,610 MBoe, and average net daily production during 2012 was approximately 400 Boe/d. During 2012, we drilled 4 vertical Cotton Valley wells in the McKamie-Patton Field.

Gas Processing Facilities. Our gas processing facilities are located in Lafayette and Columbia counties in Arkansas and are strategically located to serve our production in the region. The facilities process natural gas and natural gas liquids, fractionate liquids into three components for sale, and sell three products at the facility's tailgate: propane, natural gasolines and natural gas. We also own approximately 150 miles of natural gas gathering pipeline that serve the facilities and surrounding Field areas and 32 miles of right-of-way crossing Lafayette County that can be utilized to connect the facility to other gas Fields or future sales outlets. Natural gas is sold at the tailgate of the facilities into CenterPoint pipeline connections. Processed natural gas liquids are held on site and trucked out. All gas entering the facility is processed in accordance with percent-of-proceeds contracts with upstream counterparties.

In order to accommodate increased gas volumes and facilitate full Field development, we invested $16.2 million in 2012 to build another 12.5 MMcf/d processing facility at Dorcheat with associated 28,000 gallons per day of natural gas liquids capacity. This facility was completed in February 2013.

In aggregate, our Arkansas gas processing facilities have approximately 40 MMcf/d of capacity with associated 86,000 gallons per day of natural gas liquids capacity. Our ownership of these facilities and 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. While we own the majority of the gas entering the facilities, we also process some third-party natural gas through the system. Neither the revenue nor volumes of this third-party natural gas is included in our reserve reports.

California

During 2012, we owned acreage in four Fields in California: Kern River, Midway Sunset and Greeley, which we operated, and Sargent, which we did not. As of December 31, 2012, we had sold all of our interests in these Fields with the exception of Midway Sunset, which was in the process of being sold at year-end. Associated proved reserves as of December 31, 2012 for Midway Sunset were 31 MBoe.

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 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

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us to disclose in public reports. Our estimated proved reserves for the years ended December 31, 2012, 2011 and 2010 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.

The table below summarizes our estimated proved reserves at December 31, 2012, 2011 and 2010 for each of the areas in which we operate. All of the reserve estimates at December 31, 2012, 2011 and 2010 presented in the table below are based on reports prepared by Cawley Gillespie & Associates, Inc., our independent reserve engineers. In preparing its reports, Cawley Gillespie & Associates, Inc. evaluated 100% of our properties at December 31, 2012, 2011 and 2010. 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.

Proved Reserves

Region/Field	**At December 31, 2012 (MMBoe)**	**At December 31, 2011 (MMBoe)**	**At December 31, 2010 (MMBoe)**
Mid-Continent	**20.6**	**21.6**	**22.9**
Dorcheat Macedonia	19.0	19.9	20.8
McKamie Patton	1.6	1.6	2.0
Other	0.0	0.1	0.1
Rocky Mountain	**32.4**	**21.4**	**9.1**
Wattenberg	31.9	20.8	8.4
North Park	0.5	0.6	0.7
California	**0.0**	**0.7**	**0.9**
Total	**53.0**	**43.7**	**32.9**

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The following table sets forth more information regarding our estimated proved reserves at December 31, 2012, 2011 and 2010:

	At December 31,		
	2012	2011	2010
Reserve Data(1):			
Estimated proved reserves:			
Oil (MMBbls)	30.2	24.6	18.6
Natural gas (Bcf)	118.5	93.0	62.9
Natural gas liquids (MMBbls)	3.1	3.6	3.8
Total estimated proved reserves (MMBoe)**(2)**	53.0	43.7	32.9
Percent oil and liquids	63%	65%	68%
Estimated proved developed reserves:			
Oil (MMBbls)	14.3	10.6	7.4
Natural gas (Bcf)	48.9	31.3	20.1
Natural gas liquids (MMBbls)	1.3	1.2	0.7
Total estimated proved developed reserves (MMBoe)**(2)**	23.8	17.0	11.5
Percent oil and liquids	66%	69%	70%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	15.8	14.0	11.2
Natural gas (Bcf)	69.6	61.7	42.8
Natural gas liquids (MMBbls)	1.8	2.4	3.0
Total estimated proved undeveloped reserves (MMBoe)**(2)**	29.2	26.7	21.3
Percent oil and liquids	60%	61%	67%

(1) Proved reserves were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month prices for each of the preceding twelve months, which were $94.71 per Bbl WTI and $2.757 per MMBtu HH, $96.19 per Bbl WTI and $4.12 per MMBtu HH, $79.43 per Bbl WTI and $4.38 per MMBtu HH for the years ended December 31, 2012, 2011 and 2010 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 locations on development spacing areas that are offsetting economic producers that are reasonably certain of economic production when drilled. Proved undeveloped reserves for other undrilled development spacing areas can be claimed only where it can be demonstrated with reasonable certainty that there is continuity of economic production from the existing productive formation. All proved undeveloped locations in our December 31, 2012 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, 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 12.8 MMBoe resulting from development in the Wattenberg Field in the Rocky Mountain region is comprised of 18.9 MMBoe of additions in extensions and discoveries offset by 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

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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 Henry Hub for the year ended December 31, 2011 to $94.71 per Bbl WTI and $2.757 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 is primarily due to extensions and discoveries associated with the Rocky Mountain region and is 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.

The following table provides a reconciliation of PV-10 to the Standardized Measure at December 31, 2012, 2011 and 2010:

	December 31,		
	2012	**2011**	**2010**
		(In millions)	
PV-10	$ 834.7	$ 794.0	$ 461.6
Present value of future income taxes discounted at 10%	(151.3)	(127.8)	(86.9)
Standardized Measure	$ 683.4	$ 666.2	$ 374.7

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Proved Undeveloped Reserves

	Net Reserves, MBoe At December 31,	
	2012	**2011**
Previous Year End	26,652	21,334
Converted to Proved Developed Producing	(5,166)	(4,184)
Additions from Capital Program	13,913	10,190
Acquisitions/Sales	(430)	0
Revisions (pricing and engineering)	(5,777)	(688)
Year End	29,192	26,652

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 booking. 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 booking. At December 31, 2010, our proved undeveloped reserves were 21,334 MBoe. During 2011, 4,184 MBoe or 19.6% of our proved 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 work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserves estimation process. Our Executive Vice President of Engineering and Planning, Gary A. Grove, is the technical person primarily responsible for overseeing the reserves process and insuring compliance with the Securities and Exchange Commission (SEC) definitions and guidance. Mr. Grove has over 30 years of industry experience with positions of increasing responsibility in engineering and evaluations and holds a Bachelor of Science degree in petroleum engineering.

Throughout each fiscal year, the reserve committee of our board of directors and our technical team meet with representatives of our independent reserve engineering firm to review the reserves process and methodologies used in the estimation of the proved reserves. The reserve committee meets at least twice annually.

Our technical team also 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.

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Independent Reserve Engineers

The proved reserves estimate for the Company for the years ended December 31, 2010, 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 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. Natural gas prices have declined over the last three years as a result of a global economic downturn and increased supplies of natural gas.

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, revenues and realized prices and production costs for the periods indicated. For additional information on price

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calculations, please see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	2012(1)	2011	2010
Oil:			
Total Production (MBbls)	2,191.0	887.3	415.8
Wattenberg Field	1,190.8	400.8	134.6
Dorcheat Macedonia Field	789.5	359.8	147.9
Average sales price (per Bbl), including hedges**(2)**	88.40	$ 85.51	$ 75.88
Average sales price (per Bbl), excluding hedges**(2)**	89.08	$ 89.67	$ 74.08
Natural Gas:			
Total Production (MMcf)	5,473.2	2,773.1	1,351.5
Wattenberg Field	2,485.6	1,072.2	391.6
Dorcheat Macedonia Field	2,973.8	1,642.2	828.6
Average sales price (per Mcf), including hedges**(2)**	3.76	$ 5.09	$ 4.99
Average sales price (per Mcf), excluding hedges**(2)**	3.62	$ 4.85	$ 4.76
Natural Gas Liquids:			
Total Production (MBbls)	284.7	183.8	129.8
Wattenberg Field			
Dorcheat Macedonia Field	284.7	183.8	129.8
Average sales price (per Bbl), including hedges	55.54	67.23	56.23
Average sales price (per Bbl), excluding hedges	55.54	67.23	56.23
Oil Equivalents:			
Total Production (MBoe)	3,387.9	1,533.4	770.9
Wattenberg Field	1,605.0	579.5	199.8
Dorcheat Macedonia Field	1,569.8	817.3	416.3
Average daily production (Boe/d)	9,257	4,201.1	2,112.1
Wattenberg Field	4,385.4	1,587.7	547.4
Dorcheat Macedonia Field	4,289.1	2,239.2	1,140.5
Average Production Costs (per Boe)	9.06	13.37	16.04

(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.

(2) Excludes ad valorem and severance taxes.

Principal Customers

Two of our customers, Plains Marketing and Lion Oil, comprised 34% and 29%, respectively, of our total revenue for the year ended December 31, 2012. No other single non-affiliated purchaser accounted for 10% or more of crude oil and natural gas sales in 2012. We believe the loss of any one purchaser would not have a material effect on our financial position or results of operations, since there are numerous potential purchasers 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 oil and natural gas wells in which we owned a working interest at December 31, 2012.

	Oil		Natural Gas(1)		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	266	246.4			266	246.4	254	243.6
Mid-Continent	186	157.6			186	157.6	180	157.3
California	21	21			21	21	21	21
Total	473	425			473	425	455	421.9

(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, 2012 for each of the areas where we operate. 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
Rocky Mountain	37,086	34,837	27,317	20,453	64,403	55,290
Mid-Continent	14,840	13,367			14,840	13,367
California	480	480	120	47	600	527
Total	52,406	48,684	27,437	20,500	79,843	69,184

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2012 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 2013		Expiring 2014		Expiring 2015	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	1,017	724	481	52	3,481	3,104
Mid-Continent						
California	120	47				
Total	1,137	771	481	52	3,481	3,104

In 2012, federal and state leases covering 160 acres in our Rocky Mountain region expired, all of which were in the Wattenberg Field.

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Drilling Activity

Exploratory

The following table describes the exploratory wells we drilled during the years ended December 31, 2012, 2011 and 2010.

	Productive Wells		Dry Wells		Total	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2012			1	1	1	1
2011	53	52.9			53	52.9
2010	14	14.0			14	14.0

Development

The following table describes the development wells we drilled during the years ended December 31, 2012, 2011 and 2010.

	Productive Wells		Dry Wells		Total	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2012	149	140.9			149	140.9
2011	53	48.9			53	48.9
2010(1)	26	25.9			26	25.9

(1) We contract operated for HEC from May 2009 until we acquired the properties in December 2010. Excluded from the development activity are 15 gross (11.3 net) wells drilled as contract operator for HEC during year 2010, in which we had a minority working interest.

Present Activity

The following table describes drilling activities as of December 31, 2012.

	Development Wells		Exploratory Wells		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Rocky Mountain	1	1.0			1	1.0
Mid-Continent	3	3.0			3	3.0
California						
Total	4	4.0			4	4.0

Capital Expenditure Budget

Our anticipated 2013 capital budget is approximately $394 million which represents an increase of 16% over capital spending during 2012 of $341 million. We plan to spend approximately $324 million or 82% of our total 2013 budget in the Wattenberg Field with the remaining $70 million allocated to our assets in southern Arkansas. In total, we plan to spend $342 million on operated drilling and completion activities with the remainder allocated to non-operated drilling and completion activities, costs associated with our gas plant expansion in Arkansas, seismic and maintenance operations.

While we have budgeted approximately $394 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on, among other things, market conditions, the

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success of our drilling results as the year progresses and changes in the borrowing base under our credit facility.

Hedging 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 transactions.

As of December 31, 2012, we had the following economic hedges in place, which settle monthly:

Oil Contracts

Settlement Period	Derivative Instrument	Total Notional Amount (BBL/Mmbtu)	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability)
Oil					
2013	Collar	890,616	88.92	103.00	1,727,192
	Swap	1,035,417	88.54		(4,864,853)
2014	Collar	672,000	85.00	95.50	(1,235,168)
	Swap	228,000	90.80		(308,287)
Gas					
2013	Swap	154,806	6.40		450,872

We do not apply hedge accounting treatment to any commodity derivative contracts. Settlements on these contracts will not impact our realized commodity prices during the periods they cover. Instead, any settlements on these contracts are shown as a component of other income and expenses as a realized (gain) loss on derivative instruments. See Note 12 to our consolidated financial statements for additional information regarding our derivative instruments.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and 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. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. Generally, we make title investigations and receive title opinions of local counsel only before we commence drilling operations, subject to the availability and examination of accurate title records, except in Arkansas and certain cases in the Rocky Mountain region where we have commenced drilling without complete legal examination of title, but are in the process of obtaining title opinions. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with the operation of our business.

Bonanza Creek Acquisition History

Acquiring properties that are complementary to our existing positions or that have significant undeveloped resource potential has been an important part of our growth strategy. The following

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describes some of the acquisitions completed by our predecessor to build our current position in the Mid-Continent and the Rocky Mountain regions:

Mid-Continent. In April 2008, our predecessor BCEC acquired properties in Union, Lafayette and Columbia counties, Arkansas, that included 93 producing wells (68 operated) with an average working interest of 73% and 14,980 gross (12,147 net) acres. Included in the acquisition was a 15 MMcf/d gas plant with approximately 150 miles of gathering system, which processes production from both the properties and other producers in the area. We acquired 3,469 gross (3,018 net) acres in the Dorcheat Macedonia Field, Columbia County, Arkansas in December 2010. The assets included a non-operated position in the Dorcheat Macedonia Field as well as operated wells in which we were a non-operated owner.

Rocky Mountain. Our predecessor BCEC completed four Wattenberg Field acquisitions in 2005 and 2006, consisting of approximately 39,728 gross (27,463 net) acres. In December 2010, we purchased an additional 2,970 gross (2,279 net) acres in the Wattenberg Field, including 39 operated and 3 non-operated wells primarily completed in the Codell/ Niobrara formations. BCEC purchased the McCallum Field, located in the North Park Basin, Jackson County, Colorado in May 2006, along with 2 non-producing wells and undeveloped acreage in November 2007. In August 2012, we leased approximately 5,600 gross (5,600 net) acres from the State of Colorado in the core of our Wattenberg Field position.

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, and obtaining transportation for the oil and gas we produce in certain regions. There is also competition between producers of oil and gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

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

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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.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Failure to comply with applicable laws and regulations can result in substantial penalties and threaten loss of the authorization to operate. Furthermore, such laws and regulations are frequently amended or reinterpreted, and new proposals that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We believe we are in substantial compliance with all 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.

Regulation of transportation of oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

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.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA"), and regulations issued under those statutes. 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 market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act, which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

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FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affect the marketing of natural gas that we produce and the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open access and non-discriminatory basis.

Natural gas gathering services located upstream of jurisdictional transmission services and those located onshore and in state waters are subject to state regulation. Although FERC has set forth a general test for determining whether facilities perform a nonjurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities are done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Such regulation has not generally included regulation of the rates, terms and conditions of gathering services, although natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. 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 and the revenues we receive for sales of our natural gas.

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.

The failure to comply with these rules 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.

Market transparency rules

In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements ("Order No. 704"). Pursuant to Order No. 704, wholesale buyers and sellers of annual quantities of 2.2 million MMBtu or more of natural gas in the previous calendar year, including intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, by May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. Some of our operations may be required to comply with Order No. 704's annual reporting requirements.

On November 15, 2012, the Commission issued a Notice of Inquiry seeking comments on what additional changes, if any, should be made to its regulations under the natural gas market transparency provisions of section 23 of the NGA, as adopted in the Energy Policy Act of 2005. In particular, the Commission is considering proposing to require all market participants engaged in sales of wholesale physical natural gas in interstate commerce to report quarterly to the Commission every natural gas transaction within the Commission's NGA jurisdiction that entails physical delivery for the next day (i.e., next day gas) or for the next month (i.e., next month gas).

In October 2010, FERC issued a Notice of Inquiry seeking public comment on the issue of whether and how parties that hold firm capacity on some intrastate pipelines can allow others to use their capacity, including to what extent buy/sell transactions should be permitted and whether FERC should consider requiring such pipelines to offer capacity release programs. In the Notice of Inquiry, FERC granted a blanket waiver regarding such transactions while FERC is considering these policy issues. The comment period has ended, but FERC has not yet issued an order.

With regard to our physical sales of natural gas, we are required to observe anti-market manipulation laws and related regulations enforced by FERC. With regard to our sales of petroleum and petroleum products, we are required to observe anti-market manipulations laws and related regulations enforced by the Federal Trade Commission ("FTC"). In addition, the CFTC has enforcement authority over market manipulation with respect to certain derivative contracts.

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 requires 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.

Environmental, Health and Safety Regulation

Our exploration, development, production and processing operations are subject to various federal, state and local laws and regulations relating to health and safety, the discharge of materials and environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling and production; restrict the way we handle or dispose of our wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by protected plant and animal species; require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Environmental, health and safety laws and regulations increase the cost of doing business in the oil and gas industry and consequently affect profitability. Additionally, the Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly permitting and compliance, waste handling and disposal, cleanup or remediation requirements for the oil and gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretations of enforcement policies that result in more stringent and costly requirements could have a material adverse effect on our operations and financial position in the future. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. We maintain insurance against costs of cleanup operations, but we are not fully insured against all such risks. While we believe that we are in substantial compliance with existing environmental laws and regulations and that current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that this will continue in the future.

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

Hazardous substances and waste

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. CERCLA also authorizes EPA and, in some instances, third parties to act in response to hazardous substance threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Further, it is not uncommon for neighboring landowners and other third parties to file other claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. Although CERCLA's petroleum exclusion provision excludes "crude oil or any fraction thereof" from its definition of hazardous substance, we do generate materials in the course of our operations that may contain CERCLA hazardous substances.

We also generate solid and hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. RCRA imposes requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations we generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes, or simply as solid waste. RCRA regulations specifically exclude from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs and the natural gas and oil industry in general.

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. In December 2011, both Houses of the U.S. Congress passed bipartisan legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules. 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 is considering two 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.

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Since August 2006, the U.S. Environmental Protection Agency ("EPA") has published several new regulations under the CAA to control emissions from stationary internal combustion engines. Over time, those rules may require us to undertake certain expenditures and activities, likely including paying higher prices for new engines; installing emissions control equipment, such as oxidation catalysts or non-selective catalytic reduction equipment, on a portion of our existing engines located at major sources of hazardous air pollutants, and all our existing engines over a certain size regardless of location; following prescribed maintenance practices for engines; and implementing additional emissions testing, monitoring and recordkeeping.

On August 16, 2012, EPA published final rules that established new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA's rule package included New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities, and reduced emission completion requirements for hydraulically fractured gas wells. The rules also established specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules contain more stringent leak detection requirements for natural gas processing plants. 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. EPA intends to issue revised rules in 2013 that are likely responsive to some of these requests. The final revised rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

Climate change

The United States is a party to the United Nations Framework Convention on Climate Change, an international treaty focused on stabilizing greenhouse gas ("GHG") concentrations in the atmosphere at a level that would prevent serious damage to the Earth's climate. While neither the treaty itself, nor subsequent related conferences, have established an obligation for the U.S. to reduce its GHG emissions by a set amount, it has put significant political pressure on the U.S. to take responsive action. Both houses of Congress have previously considered legislation to reduce emissions of GHG. Any future federal laws, treaties or implementing regulations that may be adopted to address GHG emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

EPA has begun to regulate GHG emissions. In December 2009, EPA published its finding that certain emissions of GHG presented an endangerment to human health and the environment. These findings by EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHG under existing provisions of the CAA. Consequently, EPA required a reduction in emissions of GHG from new motor vehicles for the 2012 model year and subsequent years. Furthermore, EPA published a final rule on June 3, 2010 to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain major stationary sources of GHG emissions, such as power plants and oil refineries, in a multi-step process, with the largest-emitting sources first subject to permitting. Facilities required to obtain Prevention of Significant Deterioration ("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. Starting in January 2011, stationary sources that are already obtaining a PSD or Title V major source permit for other pollutants must include GHG in their permits if they emit at least 75,000 tons of these emissions per year. In July 2012, the rule expanded to include all new facilities that emit at least 100,000 tons of GHG per year.

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In addition, in October 2009, EPA issued a final rule requiring the reporting of GHG from specified large GHG emission sources beginning in 2011 for emissions in 2010. Our McKamie processing facility in Arkansas is required to report under this rule. On November 30, 2010, EPA published a final rule expanding the existing GHG monitoring and reporting rule to include certain large onshore and offshore oil and gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. Reporting of GHG emissions from such facilities is required on an annual basis and began in 2012 for emissions occurring in 2011. Our McKamie processing facility and our North Park Basin, Colorado, facility are required to report under this rule. EPA also published a final rule requiring reporting for natural gas liquid fractionators, which applies to the McKamie processing facility and a separate reporting rule for suppliers of carbon dioxide, which affects our operations in the North Park Basin. Several of EPA's GHG rules are being challenged in court proceedings, and depending on the outcome of such proceedings, such rules may be modified or rescinded or EPA could develop new rules. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations or could adversely affect demand for the oil and natural gas we produce.

Almost one-half of the states have begun taking actions to control and/or reduce emissions of GHG, primarily through the planned development of GHG emission inventories and/or GHG cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. We cannot predict with any certainty at this time how these possibilities may affect our 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, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for oil or natural gas we produce, or otherwise cause us to incur significant costs in preparing for or responding to those effects.

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. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties and other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. Surface spills and leaks are controlled, contained and remediated in accordance with the applicable requirements of state oil and gas commissions, as well as any Spill

Prevention, Control and Countermeasures ("SPCC") plans we maintain in accordance with EPA requirements. This would include any action up to and including total abandonment of the wellbore.

Endangered Species Act

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

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (the "OSH Act"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSH Act's hazard communication standard, 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. 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. The State of Colorado recently adopted regulations regarding hydraulic fracturing, which went into effect April 1, 2012. These regulations require disclosure of all chemicals used in hydraulic fracturing fluid, subject to certain measures to protect proprietary information. The regulations allow disclosure through the FracFocus web site, which is operated jointly by the Interstate Oil & Gas Compact Commission and the Ground Water Protection Council. 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. EPA recently asserted regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program and is developing guidance for how permitting authorities should handle such activities. 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 study into the effects of hydraulic fracturing on drinking water. 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. The United States Department of the Interior has also announced its intention to propose a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water.

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.

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 300 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 been used more universally since the early 1990s. We and our predecessor companies have completed over 60 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.

Other laws

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

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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.

The National Environmental Policy Act of 1969 ("NEPA"), requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment before their commencement. Generally, federal agencies must prepare either an environmental assessment or an environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the environment. The NEPA process involves public input through comments, which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the administrative and federal court systems by process participants. Although we believe that our actions do not typically trigger NEPA analysis, should we ever be subject to NEPA review, the process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of certain leases.

Our properties located in Colorado are subject to the authority of the Colorado Oil and Gas Conservation Commission ("COGCC"). 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. 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.

Employees

As of December 31, 2012, we employed 155 people. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We also utilize the services of independent contractors to perform various Field and other services.

Offices

As of December 31, 2012, we leased 42,712 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 15,182 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.

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

Item 1A. *Risk Factors.*

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

Risks related to the oil and natural gas industry and 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 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. 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

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natural gas reserves" below. 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 63% of our estimated proved reserves as of December 31, 2012 were oil and natural gas liquids reserves, 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, 2012, the daily NYMEX WTI oil spot price ranged from a high of $109.77 per Bbl to a low of 77.69 per Bbl, and the NYMEX natural gas Henry Hub spot price ranged from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu.

As of December 31, 2012, we had commodity price hedging agreements for 2013 on approximately 1.9 MMBbls of oil with an average minimum price of $88.72/Bbl and 154.8 MMcf of natural gas with an average minimum price of $6.40/Mcf. Additionally, we had 0.9 MMBbls of oil hedged in 2014 with an average minimum price of $90.30/Bbl.

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.

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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 "Item 1. Business Estimated Proved Reserves" for information about our estimated oil and natural gas reserves and the PV-10 (a non-GAAP financial measure) as of December 31, 2012, 2011 and 2010.

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

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, oil Field 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.

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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, 2012, 2011 and 2010, 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;
- 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 prices decline by $10.00/Bbl, then our PV-10 as of December 31, 2012 would decrease by approximately $161.6 million. PV-10 is a non-GAAP financial measure (refer to Item 1 Business Estimated Proved Reserves 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;
- 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.

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 oil shale, 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.

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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 were $304.6 million and $158.9 million (including $13.9 million and $1.8 million for the acquisition of oil and gas properties) related to capital and exploration expenditures for the years ended December 31, 2012 and 2011, respectively. Our capital expenditure budget for 2013 is approximately $394 million, with approximately $342 million allocated for drilling and completion operations. 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.

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Increased costs of capital could adversely affect our business.

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

We may experience difficulty in achieving and managing future growth.

We have experienced growth in the past primarily through the expansion of our drilling program and acquisitions. 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.

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 93% of our current production, each of our development projects and most of our exploration potential. During 2012, we initiated a non-core divestiture program to focus our portfolio and sold certain non-core assets in California. As a result of these portfolio changes, our operations and production are more concentrated.

The Wattenberg and Dorcheat Macedonia Fields represent 47% and 46%, respectively, of our 2012 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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Market conditions or operational impediments, like lack of available transportation, may hinder our production or adversely impact our ability to receive market prices for our production or to achieve expected drilling results.

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 availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. 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. 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 other disruptions of service. Curtailments and disruptions may last from a few days to several months, and we have no control over when or if third-party facilities are restored. Recently, the gas gathering systems serving the Wattenberg Field have 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 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 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 55% of our total proved reserves were classified as proved undeveloped as of December 31, 2012. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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

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

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According to estimates included in our December 31, 2012 proved reserve report, if, on January 1, 2013, 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 8.9% over 10 years, including 54.2% during the first year. If we fail to replace reserves through drilling, our level of production and cash flows will be affected adversely. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both.

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.

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 (including releases at our gas processing facilities) or of other substances such as petroleum liquids or drilling fluids, into the environment;
- 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);
- 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.

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 are susceptible to damage from natural disasters such as flooding 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

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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 interpretation. 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.

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, 2012, only 329 gross (244.5

net) of our approximately 1,600 identified potential future gross drilling locations were 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 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 certain of our oil and gas leases stipulate that the lease will terminate if not held by production. As of December 31, 2012, all of our acreage in Arkansas was held by production and not subject to lease expiration. As of December 31, 2012, 10,127 net acres of our properties in the Rocky Mountain region, specifically 7,497 acres in the Wattenberg Field and 2,630 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 three years, then 724 net acres will expire in 2013, 52 net acres will expire in 2014 and 3,104 net acres will expire in 2015. If our leases expire, we will lose our right to develop the related properties.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in oil and natural gas leasehold interests from third parties or directly from the mineral fee owners. The existence of a title deficiency can reduce or destroy the value of a lease and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available. We forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled, except in Arkansas and certain cases in the Rocky Mountain region where we have commenced drilling without complete legal examination of title, but are in the process of obtaining title opinions. As is customary in our industry, we rely upon the judgment of oil and natural gas lease brokers, in-house landmen or independent landmen who perform the Field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. We do not always perform curative work to correct deficiencies in the marketability of the title to us. In cases involving more serious title problems, the amount paid for affected oil and natural gas leases can be lost, and the target area can become undrillable. We may be subject to litigation from time to time as a result of title issues.

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 on shale drilling in the United States, even in jurisdictions that are

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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 disposition 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 EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our operations; delays in granting permits, or even the cancellation of leases.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions 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

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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. Recently, the Environmental Protection Agency 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. 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. After several parties challenged the new air regulations in court, the EPA announced that it intends to grant requests for reconsideration of certain requirements and to evaluate 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 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 restrict its use. For example, the EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing. 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. Legislation has also been introduced in the United States Congress that would amend the federal Safe Drinking Water Act ("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 permits for fracturing, 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. At this time, it is not clear what action, if any, the United States Congress will take on hydraulic fracturing. Beyond that, the U.S. Department of the Interior proposed a new rule regulating hydraulic fracturing activities on federal lands that would have covered disclosure, well bore integrity, and handling of flowback water, but now intends to issue a revised proposal.

In addition to these ongoing federal initiatives, state and local governments where we operate have moved to require disclosure of fracturing fluid components or otherwise regulate their use more closely. In certain areas of the country, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. Similarly, governmental authorities continue to develop requirements for the emission of greenhouse gases that are being linked to climate change.

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

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

There is a growing belief that human-caused (anthropogenic) emissions of greenhouse gases ("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, 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 EPA, contributing to the warming of the Earth's atmosphere and other climatic changes. Consistent with its findings, EPA has proposed or adopted various regulations under the Clean Air Act to address GHG. Among other things, EPA is limiting emissions of GHG from new cars and light duty trucks beginning with the 2012 model year. In addition, 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. 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, and which may form the basis for further GHG regulation. Many of EPA's GHG rules are subject to legal challenges, but have not been stayed pending judicial review. Depending on the outcome of such proceedings, such rules may be modified or rescinded or EPA could develop new rules. 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, 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 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.

The loss of senior management or technical personnel 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 or technical personnel, including Michael R. Starzer, our President and Chief Executive Officer, 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.

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We recorded substantial compensation expense in 2012, and we are likely to incur substantial additional compensation expense related to our future grants of stock compensation, which may have a material negative impact on our operating results for the foreseeable future.

We incurred compensation expense in 2012 in the amount of $4.5 million compared to $4.4 million in 2011. 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 and other risks associated with our business.

The Dodd-Frank Act, which was signed into law on July 21, 2010, contains significant derivatives regulation. The Dodd-Frank Act and any new regulations promulgated under the act 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. We may need to expend significant resources complying with and adapting to the new regulatory regime, including significant reporting and record keeping requirements, as well as otherwise ensuring that we are able to rely on certain exemptions from mandatory clearing requirements. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become 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

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prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings. If amounts outstanding under our revolving credit facility were to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources."

Our revolving credit facility contains operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility contains a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets;
- pay distributions on, redeem or repurchase our common stock;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- make certain acquisitions and investments;

consolidate, merge or transfer all or substantially all of our assets;

engage in transactions with affiliates;

create unrestricted subsidiaries; and

engage in certain business activities.

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As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our level of indebtedness may increase and reduce our financial flexibility.

As of December 31, 2012, we had $158 million of indebtedness outstanding under our revolving credit facility, and $119 million available for future secured borrowings under this facility. 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:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may 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; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt, and future working capital borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

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 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 $38.6 million in receivables at December 31, 2012.

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, 2012, sales to Lion Oil Trading & Transport and Plains Marketing accounted for approximately 29% and 34%, 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 the Company's 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 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.

The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions 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. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to 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.

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. 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 prospectus and contained in our reports filed with the SEC, 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. Project Black Bear LP ("Black Bear") and Her Majesty the Queen in Right of Alberta, in her own capacity and as trustee/nominee for certain Alberta pension clients ("HMQ"), own 8,166,134 shares, or approximately 20.34% of our total outstanding shares. These stockholders are parties to a registration rights agreement with us. Pursuant to this agreement, we have agreed to effect the registration of shares held by Black Bear and HMQ if they so request 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.

We may issue debt and equity securities or securities convertible into equity securities, any of which may be senior to our common stock as to distributions and liquidation.

We have filed a shelf registration statement that gives us the ability to issue a number of different securities. In the future, we may issue debt or equity securities or securities convertible into or exchangeable for equity securities, or we may enter into debt-like financing that is unsecured or secured by any or all of our properties. Such securities may be senior to our common stock as to distributions. In addition, in the event of our liquidation, our lenders and holders of our debt and preferred securities would receive distributions of our available assets before distributions to the holders of our common stock.

Our certificate of incorporation and bylaws contain, and Delaware law contains, provisions that may prevent, discourage or frustrate attempts to replace or remove our current management by our stockholders, even if such replacement or removal may be in our stockholders' best interests.

Our certificate of incorporation and bylaws contain, and Delaware law contains, provisions that could enable our management to resist a takeover attempt. Among other things, our certificate of incorporation and bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to director nominations or new business to be brought before stockholder meetings. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate

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secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our bylaws specify the requirements as to form and content of all stockholder notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

provide our board of directors the ability to authorize undesignated preferred stock and to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to gain control of us. These and other provisions may have the effect of deterring hostile takeovers or delaying changes in control or management of our company;

provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any. This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;

provide that the authorized number of directors may be changed only by resolution of the board of directors;

provide that all vacancies, including newly created directorships, may, except as otherwise required by law, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

provide that stockholders may only act at a duly called meeting and may not act by written consent in lieu of a meeting;

provide that special meetings of stockholders may only be called by our board of directors, the Chairperson, the Chief Executive Officer or the President and not by our stockholders; and

provide that our board of directors may alter or repeal our bylaws or approve new bylaws without further stockholder approval.

These provisions could:

discourage, delay or prevent a change in the control of our company or a change in our management, even if the change would be in the best interests of our stockholders;

adversely affect the voting power of holders of common stock; and

limit the price that investors might be willing to pay in the future for shares of our common stock.

West Face Capital Inc. and Alberta Investment Management Corporation together 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.

West Face Capital, Inc. ("West Face"), as advisor to Black Bear, and Alberta Investment Management Corporation, a Canadian corporation and investment manager to HMQ and certain Alberta pension funds ("AIMCo"), together may be deemed to beneficially own, control or have substantial influence over approximately 20.34% of our outstanding common stock. West Face Capital and AIMCo, on behalf of HMQ and certain Alberta pension funds, have entered into an investment

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management agreement pursuant to which West Face Capital has the right to vote the shares of our common stock held by HMQ. West Face Capital also has the right, pursuant to an advisory agreement with Black Bear, to vote the shares held by Black Bear. Accordingly, West Face Capital 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, West Face Capital and AIMCo, on behalf of its clients, voting together as a group would have the ability to exert significant influence over the company.

A concentration of ownership in West Face Capital alone or together with 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;
- the payment of dividends on our common stock;
- 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 Black Bear and 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 incorporated herein by reference.

Item 3. *Legal Proceedings.*

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

In June 2011, Frank H. Bennett, a co-manager of Bonanza Creek Oil Company, LLC ("BCOC"), Bonanza Creek Energy, LLC's ("BCEC") predecessor, and former chairman of BCEC, made a demand against Michael R. Starzer, our President and Chief Executive Officer, focusing on Mr. Starzer's handling of the operation, accounting and finances of BCOC and BCEC primarily during the 2005-2006 time period. Mr. Bennett's demands do not allege any wrongdoing by or claims against Bonanza Creek Energy, Inc. This matter was sent to arbitration in July 2011. An arbitration hearing commenced in July

2012 and concluded in October 2012. At the end of November 2012, the arbitration panel issued an order finding in favor of Mr. Starzer on all of the plaintiff's claims. This order is final and non-appealable, thus effectively and favorably terminating the claims asserted by Mr. Bennett. During the period from January 1, 2012 through December 31, 2012, the Company incurred approximately $3,000,000 for legal fees and other expenses related to Mr. Bennett's claims.

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 New York Stock Exchange ("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 since our initial public offering.

	High	Low
4th Quarter 2011 (from December 15, 2011)	$ 15.50	$ 12.39
1st Quarter 2012	22.25	12.62
2nd Quarter 2012	22.66	14.52
3rd Quarter 2012	24.40	15.00
4th Quarter 2012	29.03	20.83
1st Quarter 2013 (through February 28, 2013)	35.25	29.23

Holders. As of February 28, 2013, there were approximately 87 registered holders of our common stock.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility 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 28, 2013, the last sale price of our common stock, as reported on the NYSE, was $33.83 per share.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2012:

Period	Total Number of Shares Exchanged(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
Oct 1 Oct 31, 2012		$		
Nov 1 Nov 30, 2012	3,108	22.81		
Dec 1 Dec 31, 2012	14,578	26.17		
Total	17,686	$ 25.58		

(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, 2012.

Use of Proceeds. As a result of our IPO, we received net proceeds of $155.9 million, after deducting underwriting discounts and commissions and other offering expenses. None of the expenses associated with our IPO were paid to directors, officers or persons owning ten percent or more of our common stock or to their associates, or to our affiliates. As of December 31, 2011, we had used approximately $155 million of those proceeds for the repayment of indebtedness, and the remaining 0.9 million was used during the year ended December 31, 2012 for the exploration and development of oil and gas properties. There was no material change in the planned use of proceeds from our initial public offering as described in our final prospectus filed with the SEC pursuant to Rule 424(b) on December 19, 2011.

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 New York Stock Exchange) and the last trading day of the fiscal years ended December 31, 2011 and 2012. 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 following tables set forth selected historical financial data of the Company and our predecessor, BCEC, as of and for the period indicated. Selected historical financial data of the Company and BCEC for all periods prior to December 31, 2011, have been recast to present the results of operations and financial position of the Company related to certain properties in California sold in 2012 or held for sale as of December 31, 2012, as discontinued operations. See the Company's Current Report on Form 8-K filed on January 28, 2013. See also "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of Part II of this Annual Report on Form 10-K and Note 4 to the consolidated financial statements in Item 8 of Part II of this Annual Report on Form 10-K.

In management's opinion, the financial statements include all adjustments necessary for the fair presentation of our financial condition as of such date and our results of operations for such periods.

The selected historical financial data should be read in conjunction with "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and both our and our predecessor's

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financial statements and the notes to those financial statements included in Item 8 of Part II of this Annual Report on Form 10-K.

	Bonanza Creek Energy Company LLC ("Predecessor")			Bonanza Creek Energy, Inc.			
	2008	2009	Period Ended December 23, 2010(1)	Period from Inception (December 23, 2010) to December 31, 2010	Year Ended December 31, 2011	Year Ended December 31, 2012	Pro Forma 2010(2)
			(in thousands, except per share amounts)				(unaudited)
Statement of Operations Data:							
Revenues:							
Oil sales	$ 27,171	$ 22,377	$ 29,608	$ 1,200	$ 79,568	$ 195,175	$ 40,466
Natural gas sales	5,160	3,655	6,226	207	13,442	19,795	10,253
Natural gas liquids and CO_2 sales	2,782	3,169	7,672	213	12,714	16,235	8,365
Total revenues	35,113	29,201	43,506	1,620	105,724	231,205	59,084
Operating expenses:							
Lease operating	8,633	10,745	11,948	419	18,253	30,695	14,377
Severance and ad valorem taxes	1,439	1,984	1,468	66	5,918	13,674	2,368
Depreciation, depletion and amortization	11,065	12,594	12,598	436	28,014	66,202	18,856
General and administrative	7,477	7,610	8,375	324	13,164	26,922	9,339
Employee stock compensation(3)					4,449	4,483	
Exploration	9		226		878	10,715	246
Impairment of oil and gas properties(4)	1,594				623	611	
Cancelled private placement(5)			2,378				2,378
Total operating expenses	30,217	32,933	36,993	1,245	71,299	153,302	47,564
Income (loss) from operations	4,896	(3,732)	6,513	375	34,425	77,903	11,520
Other income (expense):							
Interest expense	(12,227)	(16,582)	(18,001)	(58)	(4,017)	(4,133)	(1,263)
Amortization of debt discount	(5,987)	(7,963)	(8,862)				
Write off of deferred financing costs			(1,663)				(1,663)
Gain on sale of oil and gas properties	8						
Unrealized gain (loss) in fair value of warrant put option(6)	70,972	(80,640)	34,345				
Unrealized gain (loss) in fair value of commodity derivatives	48,716	(34,589)	(7,605)	(514)	225	1,650	(8,119)
Realized gain (loss) on settled commodity derivatives	1,913	13,451	5,919	(47)	(3,024)	(725)	5,872
Other income (loss)	(229)	(180)	19		(110)	(133)	(46)
Total other income (expense)	103,166	(126,503)	4,152	(619)	(6,926)	(3,341)	(5,219)
Income (loss) from continuing operations before taxes	108,062	(130,235)	10,665	(244)	27,499	74,562	6,301
Income tax benefit (expense)(7)				90	(12,890)	(29,991)	(2,319)
Income (loss) from continuing operations	108,062	(130,235)	10,665	(154)	14,609	44,571	3,982
Discontinued operations(8)							
(Loss) income from operations associated with oil and gas properties held for sale (including impairments in 2008, 2009, 2011, and 2012 of $24.8 million, $0.6 million, $3.4 million, and $1.6 million respectively)(4)	(39,308)	149	64	(13)	(3,610)	(927)	(312)
Gain on sale of oil and gas properties		303	4,055			4,192	4,055
Income tax (expense) benefit				5	1,692	(1,313)	(1,377)
(Loss) income from discontinued operations	(39,308)	452	4,119	(8)	(1,918)	1,952	2,366
Net income (loss)	$ 68,754	$ (129,783)	$ 14,784	$ (162)	$ 12,691	$ 46,523	$ 6,348

Basic and Diluted Income Per Share(9)				
Income from continuing operations	$	$ 0.49	$ 1.12	$ 0.14
Income from discontinued operations	$	$ (0.6)	$ 0.05	$ 0.08
Net income per common share	$	$ 0.43	$ 1.17	$ 0.22
Weight Average Shares Outstanding, Basic and Diluted	29,123	29,576	39,788	29,123

(1) We completed our Corporate Restructuring on December 23, 2010.

(2) The pro forma information above gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010. See " Unaudited Pro Forma Financial Data."

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(3) In connection with our IPO, the Company distributed 243,945 fully vested shares of common stock previously held in trust to our employees and recorded a $4.1 million stock compensation charge. In addition, the Company distributed the remaining 3,400 shares of our former Class B common stock to our employees. In connection with our IPO, all issued and outstanding shares of our former Class B Common Stock converted into 437,787 shares of restricted common stock, vesting over a three year period and we recorded a $0.1 million stock compensation charge. In connection with our LTIP, the company granted 736,780 shares of restricted common stock during 2012, vesting over a three year period. We expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2013, 2014, and 2015 of approximately $6.5 million, $6.3 million, and $1.1 million, respectively.

(4) The impairment for the year ended 2008 resulted from a write-down of the carrying value of our oil and natural gas reserves due to depressed year-end natural gas prices. 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.

(5) Expenditures in connection with a cancelled private placement of our preferred stock.

(6) In connection with its purchase of our senior subordinated notes D.E. Shaw Synoptic Portfolios 5, L.L.C. received warrants to purchase equity interests in our predecessor. These warrants contained a put right exercisable beginning on May 17, 2014. The periods presented for our predecessor reflect the changes in the fair market value of that put option. The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(7) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Our pro forma results reflect our taxation as a subchapter "C" corporation at an estimated combined state and federal income tax rate of 36.8%.

(8) The results of operation and impairment loss related to non-core properties interests in California sold in 2012 or held for sale have been reflected as discontinued operations. See Note 4 to our consolidated financial statements included in Item 8 of Part II of this Annual Report on Form 10-K.

(9) As a limited liability company, ownership interests in our predecessor were held as units rather than shares.

	Bonanza Creek Energy Company, LLC (Predecessor) As of December 31,		Bonanza Creek Energy, Inc. As of December 31,		
	2008	2009	2010	2011	2012
			(in thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 4,088	$ 2,522	$	$ 2,090	$ 4,268
Property and equipment, net	182,976	177,126	481,374	618,229	943,175
Oil and gas properties held for sale, less accumulated depreciation and depletion	12,304	11,241	15,208	9,896	582
Total assets	241,625	211,552	516,104	664,349	1,002,490
Long term debt, including current portion:					
Credit facility	107,000	99,000	55,400	6,600	158,000
Senior subordinated notes, net of discount	75,499	92,442			
Subordinated unsecured note	10,000	10,799			
Warrant put options(1)	828	81,468			
Total members'/stockholders' equity (deficit)	35,988	(93,795)	356,380	527,982	578,518

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	Bonanza Creek Energy Company, LLC (Predecessor)		Bonanza Creek Energy, Inc.			
	Year Ended December 31,		Period Ended December 23,	Inception (December 23, 2010) to December 31,	Year Ended December 31,	Year Ended December 31,
	2008	2009	2010	2010(2)	2011	2012
	(in thousands)					
Other Financial Data:						
Net cash provided by (used in) operating activities	$ 11,128	$ 11,134	$ 22,759	$ (1,633)	$ 57,603	$ 156,910
Net cash provided by (used in) investing activities	(79,581)	(7,185)	(32,127)	(817)	(158,902)	(304,551)
Net cash provided by (used in) financing activities	72,541	(5,515)	9,297		103,389	149,819

(1) The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(2) We completed our Corporate Restructuring on December 23, 2010.

Unaudited Pro Forma Financial Information

We completed our Corporate Restructuring on December 23, 2010. The following unaudited pro forma financial information shows the pro forma effect of our Corporate Restructuring. We have not included a pro forma balance sheet since the effects of our Corporate Restructuring are reflected in the December 31, 2010 balance sheet included elsewhere in this Annual Report on Form 10-K. The unaudited pro forma statement of operations for the year ended December 31, 2010 was prepared as if our Corporate Restructuring had occurred at January 1, 2010.

The accompanying financial information was from the historical accounting records. We made no additional pro forma adjustment to general and administrative expense since we were the operator of all acquired properties prior to their acquisition.

The following unaudited pro forma financial statements do not purport to represent what our actual results of operations would have been if our Corporate Restructuring had occurred on January 1, 2010. The unaudited pro forma financial statements should be read in conjunction with our historical

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financial statements and related notes for the periods presented included elsewhere in this Annual Report on Form 10-K.

	Bonanza Creek Energy Company, LLC Period Ended December 23, 2010	Holmes Eastern Company, LLC Period Ended December 23, 2010	Bonanza Creek Energy, Inc. Period from Inception (December 23, 2010) to December 31, 2010	Pro Forma Adjustments (unaudited)	Bonanza Creek Energy, Inc. Year Ended December 31, 2010 (unaudited)
	(in thousands, except per share data)				
Revenues:					
Oil, natural gas, natural gas liquids and CO_2 sales	$ 43,506	$ 13,958	$ 1,620	$	$ 59,084
Operating expenses:					
Lease operating	11,948	2,010	419		14,377
Severance and ad valorem taxes	1,468	834	66		2,368
Exploration	227	19			246
Depreciation, depletion and amortization(1)	12,598	3,006	436	2,816	18,856
General and administrative	8,375	640	324		9,339
Cancelled private placement	2,378				2,378
Total operating expenses	36,994	6,509	1,245	2,816	47,564
Income from operations	6,512	7,449	375	(2,816)	11,520
Other income (expense):					
Other income (loss)	19	(65)			(46)
Write off of deferred financing costs	(1,663)				(1,663)
Unrealized gain on fair value of warrant put option(2)	34,345			(34,345)	
Amortization of debt discount(3)	(8,862)			8,862	
Realized gain on settled commodity derivatives	5,919		(47)		5,872
Unrealized loss in fair value of commodity derivatives	(7,605)		(514)		(8,119)
Interest expense(4)	(18,001)	(439)	(57)	17,234	(1,263)
Total other income (expense)	4,152	(504)	(618)	(8,249)	(5,219)
Income (loss) from continuing operations	10,664	6,945	(243)	(11,065)	6,301
Pro forma income tax expense(5)				(2,319)	(2,319)
Income (loss) from continuing operations					$ 3,982
(Loss) income from operations associated with oil and gas properties held for sale	65		(13)	(364)	(312)
Gain on sale of oil and gas properties	4,055				4,055
Pro forma income tax (expense) benefit(5)				(1,377)	(1,377)
Income from discontinued operations	4,120		(13)	(1,741)	2,366
Net Income	$ 14,784	$ 6,945	$ (256)	$ (15,125)	$ 6,348
Basic and diluted income per share					
Income from continuing operations					$ 0.14

Income from discontinued operations	$	0.08
Net income per common share	$	0.22

(1) Pro forma depletion expense gives effect to our Corporate Restructuring which required the application of purchase accounting. The expense was calculated using estimated proved reserves as of the beginning of the

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period, production for the applicable period, and the fair value of the purchase price allocated to proved oil and gas properties.

(2) BCEC issued an aggregate of 33,089 warrants to purchase Class A units during 2006, 2007, and 2008 in connection with the sale of senior subordinated notes. These warrants included a one-time right and option to put the warrants back to BCEC at fair market value less the exercise price. This pro forma adjustment reverses the mark-to-market income for the warrant put right that was recorded during 2010. This presentation assumes that the warrants were exercised on January 1, 2010 in connection with a recapitalization.

(3) During 2010, BCEC recorded accretion expense for the subordinated debt discount. This pro forma adjustment reverses the accretion expense recorded during 2010. This presentation assumes that the subordinated debt was paid off on January 1, 2010 in connection with a recapitalization.

(4) This pro forma adjustment reduces interest expense by $10.9 million for BCEC interest expense that was paid in kind during 2010, a further reduction to interest expense for the amortization of debt issuance costs related to BCEC's second lien term loan that was entered into during 2010, and a further reduction for cash interest expense paid on the revolving credit facilities of BCEC and HEC and BCEC's related party note payable during 2010. This presentation assumes that BCEC's subordinated debt, the second lien term loan and BCEC's related party note payable were paid off and the balance outstanding on our revolving credit facility was reduced on January 1, 2010 in connection with a recapitalization.

(5) Pro forma income taxes related to our pre-tax income for the year ended December 31, 2010 and is based on our expected tax rate of 36.8%.

Pro Forma Reserve Quantity and Standardized Measure Information

The following table sets forth certain unaudited pro forma information concerning our proved oil and gas reserves giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests we acquired in our Corporate Restructuring, and are located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities 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 for which relatively major expenditures are required for completion.

The estimate of proved reserves and related valuations for the period ended December 23, 2010 was based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants as of December 31, 2010, adjusted for eight days of operations. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. These estimates do not include probable or possible reserves. The information provided does not represent our estimate of expected future cash flows or value of proved oil and gas reserves.

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Changes in estimated reserve quantities:

	Oil (MBbl)			Natural Gas (MMcf)		
	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Balance December 31, 2009	15,270	6,118	21,388	27,610	16,565	44,175
Extensions and discoveries	1,258	50	1,308	2,249	228	2,477
Sales of minerals in place	(559)		(559)			
Production	(595)	(138)	(733)	(1,309)	(781)	(2,090)
Revisions to previous estimates	1,302	(308)	994	12,674	5,690	18,364
Balance December 23, 2010	16,676	5,722	22,398	41,224	21,702	62,926
Proved developed reserves:						
December 31, 2009	4,710	1,292	6,002	7,021	5,346	12,367
December 23, 2010	6,465	1,734	8,199	13,703	6,413	20,116
Proved undeveloped reserves:						
December 31, 2009	10,560	4,826	15,386	20,589	11,219	31,808
December 23, 2010	10,211	3,988	14,199	27,521	15,289	42,810

The following table sets forth unaudited pro forma information concerning the discounted future net cash flows from our proved oil and gas reserves as of December 23, 2010, net of income tax expense, and giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. 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 carryforwards 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. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of our oil and natural gas properties.

Standardized Measure from estimated production of proved oil and gas reserves as of December 23, 2010 (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Future cash flows	$ 1,366,948	$ 528,802	$ 1,895,750
Future production costs	(434,498)	(138,515)	(573,013)
Future development costs	(222,007)	(130,202)	(352,209)
Future income tax expense	(126,005)	(57,242)	(183,247)
Future net cash flows	584,438	202,843	787,281
10% annual discount for estimated timing of cash flows	(299,329)	(113,149)	(412,478)
Standardized Measure	$ 285,109	$ 89,694	$ 374,803

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

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Changes in Standardized Measure from proved oil and gas reserves (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Beginning of period	$ 185,704	$ 58,150	$ 243,854
Sale of oil and gas produced, net of production costs	(31,916)	(11,113)	(43,029)
Net changes in prices and production costs	97,744	42,468	140,212
Extensions, discoveries and improved recoveries	17,405	590	17,995
Development costs incurred	21,615	9,342	30,957
Changes in estimated development cost	(30,350)	(14,006)	(44,356)
Sales of mineral in place	(10,799)		(10,799)
Revisions of previous quantity estimates	65,959	11,833	77,792
Net change in income taxes	(38,932)	(10,019)	(48,951)
Accretion of discount	20,368	7,183	27,551
Changes in production rates and other	(11,689)	(4,734)	(16,423)
End of period	$ 285,109	$ 89,694	$ 374,803

Average wellhead prices inclusive of adjustments for quality and location used in determining future net revenues related to the Standardized Measure calculation as of December 23, 2010 were calculated using the first-day-of-the-month price for each of the 12 months that made up the reporting period.

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC
Oil (per Bbl)	$ 74.77	$ 75.33
Gas (per Mcf)	$ 4.72	$ 4.98

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."

Despite the uncertainty surrounding the global economy and continued volatility in commodity prices, we believe our portfolio positions us well moving forward. Our operations are focused in the Wattenberg Field in the DJ Basin of Colorado and the Cotton Valley sands of southern Arkansas. The low risk, oily and stable production profile of our Arkansas assets provides a strong cash flow base from which to develop the Niobrara and Codell formations in Colorado. Our corporate strategy is to create shareholder value by increasing production in our current assets, while opportunistically seeking strategic acquisitions in other high return basins across the United States where we can apply our core competencies of horizontal drilling and fracture stimulation. We maintain a high working interest in our properties and operate all of our proved reserves.

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Financial and Operating Highlights

Our 2012 financial results included:

- Net income of $46.5 million (including approximately $44.6 million from continuing operations), as compared with $12.7 million (including approximately $14.6 million from continuing operations) for 2011;
- Dry hole cost of $8.4 million, as compared with nil for 2011;
- Gain on divestitures of $4.2 million, as compared with nil for 2011;
- Cash flows provided by operating activities of $156.9 million, as compared with $57.6 million in 2011;
- Capital expenditures of $340.9 million, as compared with $165.5 million in 2011; and
- Total liquidity of $123.3 million at December 31, 2012, consisting of year-end cash balance plus funds available under our credit facility, as compared with $215.5 million at December 31, 2011.

We delivered significant growth in 2012. Operational highlights for 2012 included the following:

- Increased production by 121% to 3,387.9 MBoe in 2012 from 1,533.4 MBoe in 2011, with oil and NGL production representing 73% of total production;
- Decreased average production costs per Boe by 24% to $9.06 per Boe in 2012 from $11.90 per Boe in 2011, primarily as a result of our decision to transition from vertical wells to horizontal wells in the Wattenberg Field in July 2011;
- Increased proved reserves to 53 MMBoe as of December 31, 2012, an increase of 21% from December 31, 2011;
- Drilled our first horizontal Codell, Niobrara "C" Bench and extended reach Niobrara "B" Bench wells in the Wattenberg Field;
- Increased the amount of our credit facility from $300 million to $600 million and our borrowing base from $245 million to $325 million;
- Completed a bolt-on acquisition in the Wattenburg Field for $57 million, payable over four years, to enhance our existing operations and capitalize on our technical advantage in the field;
- Sold non-core properties in California to focus on the Wattenburg Field in the Rocky Mountains and the Dorcheat-Madeconia and McKamie-Patton fields in Arkansas; and
- Completed the expansion of our gas processing plant in Arkansas.

Outlook for 2013

We continue to monitor the outlook for the global economy and numerous critical factors including the United States federal budget deficit and long-term fiscal situation, the European debt crisis, and their potential impacts on global economic growth and commodity prices. Because the global economic outlook and commodity price environment are uncertain, we have planned a flexible capital spending program. We estimate our total capital expenditures for 2013 to be $394 million, allocated approximately 80% to the Wattenberg Field and 20% 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 budget as appropriate. This capital investment is expected to produce 2013 average sales volumes of 14,500 to 16,000 Boe/d, while maintaining a strong oil and liquids profile.

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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 of Part II of this Annual Report on Form 10-K. Comparative results of operations for the period indicated are discussed below.

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

Revenues

	Year Ended December 31, 2012	Year Ended December 31, 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 hedging)(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 hedging)(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) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

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

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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.

Operating Expenses

	Year Ended December 31, 2012	Year Ended December 31, 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)%

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.

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

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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 is 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. See Item 3 "Legal Proceedings."

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 costs. 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 of Colorado; 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.

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Realized loss on settled commodity derivatives. Realized losses on oil and gas hedging activities decreased by $2.3 million from a loss of $3.0 million for the year ended December 31, 2011 to a loss of $0.7 million for the year ended December 31, 2012. The decrease in realized cash hedge loss period over period was related to oil and natural gas prices that were one percent and 25% lower, respectively, during the year ended December 31, 2012 as compared to the year ended December 31, 2011.

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.

Year Ended December 31, 2011 Compared to Period Ended December 23, 2010

We completed our Corporate Restructuring on December 23, 2010. The operating results presented below for the audited period ended December 23, 2010 exclude the audited eight-day period from inception through December 31, 2010. The operating results of BCEI for the eight-day period from December 23, 2010 through December 31, 2010 were net revenues, operating expense, and income from operations of approximately $1.6 million, $1.2 million, and $0.4 million, respectively, and did not include transactions that were inconsistent or unusual when compared to the results for the audited period ended December 23, 2010. Other expense during this period was primarily comprised of a $0.5 million unrealized loss in the fair value of commodity derivatives.

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Year Ended December 31, 2011 Compared to Period Ended December 23, 2010

Revenues

	Year Ended December 31, 2011	Period Ended December 23, 2010	Change	Percent Change
Revenues (in thousands, except percentages):				
Crude oil sales	$ 79,568	$ 29,609	$ 49,959	169%
Natural gas sales	13,442	6,226	7,216	116%
Natural gas liquids sales	12,358	7,088	5,270	74%
CO_2 sales	356	583	(227)	(39)%
Product revenues	$ 105,724	$ 43,506	$ 62,218	143%
Sales volumes:				
Crude oil (MBbls)	887.4	401.4	486.0	121%
Natural gas (MMcf)	2,773.1	1,308.5	1,464.6	112%
Natural gas liquids (MBbls)	183.8	126.5	57.3	45%
Crude oil equivalent (MBoe)(1)	1,533.4	746.0	787.4	106%
Average Sales Prices (before hedging)(2):				
Crude oil (per Bbl)	$ 89.67	$ 73.75	$ 15.92	22%
Natural gas (per Mcf)	4.85	4.76	0.09	2%
Natural gas liquids (per Bbl)	67.23	56.04	11.19	20%
Crude oil equivalent (per Boe)(1)	68.72	57.54	11.18	19%
Average Sales Prices (after hedging)(2):				
Crude oil (per Bbl)	$ 85.51	$ 75.69	$ 9.82	13%
Natural gas (per Mcf)	5.09	5.01	0.08	2%
Natural gas liquids (per Bbl)	67.23	56.04	11.19	20%
Crude oil equivalent (per Boe)(1)	66.75	59.02	7.73	13%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

(2) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

Revenues increased by 143% to $105.7 million for the year ended December 31, 2011 compared to $43.5 million for the period ended December 23, 2010. Oil production increased 121% and natural gas production increased 112% during the year ended December 31, 2011 as compared to the period ended December 23, 2010. The most significant components of the increased production were related to an increased drilling program and the acquisition of HEC, which occurred on December 23, 2010. Our product revenues and production for the period ended December 23, 2010 excluded HEC revenues and production of $14.0 million and 268.2 Mboe, respectively. The increase in net revenues was also the result of a 22% increase in oil prices with a 2% increase in natural gas prices, respectively, for an overall increase of 19% per Boe. Also contributing to the increased revenue was a 106% increase in production attributable to our drilling program. During 2011, we drilled and completed approximately 100 wells as compared to 42 wells during 2010.

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Operating Expenses

	Year Ended December 31, 2011	Period Ended December 23, 2010	Change	Percent Change
Expenses (in thousands, except percentages)				
Lease operating	$ 18,253	$ 11,948	$ 6,305	53%
Severance and ad valorem taxes	5,919	1,468	4,451	303%
General and administrative	17,613	8,375	9,238	110%
Depreciation, depletion and amortization	28,014	12,598	15,416	122%
Exploration	877	227	650	286%
Impairment of oil and gas properties	623		623	100%
Cancelled private placement		2,378	(2,378)	(100)%
Operating expenses	$ 71,299	$ 36,994	$ 34,305	93%
Expenses per Boe:				
Lease operating	$ 11.90	$ 16.02	$ (4.12)	(26)%
Severance and ad valorem taxes	3.86	1.97	1.89	96%
General and administrative	11.49	11.23	0.26	2%
Depreciation, depletion and amortization	18.27	16.89	1.38	8%
Exploration	0.57	0.30	0.27	90%
Impairment of oil and gas properties	0.41		0.41	100%
Cancelled private placement		3.19	(3.19)	(100)%
Operating expenses	$ 46.50	$ 49.60	$ (3.10)	(6)%

Lease operating expenses. Our lease operating expenses increased $6.3 million, or 53%, to $18.3 million for the year ended December 31, 2011 from $12.0 million for the period ended December 23, 2010 and decreased on an equivalent basis from $16.02 per Boe to $11.90 per Boe. The increase in lease operating expense was related to increased production volumes due to the acquisition of HEC on December 23, 2010 and increased production attributable to our drilling program. The period ended December 23, 2010 does not include HEC lease operating expenses, which were $2.0 million. During the year ended December 31, 2011, gauging and pumping, compressor rentals, well servicing and testing, and gas plant maintenance and repairs were $1.8 million, $1.0 million, $1.0 million and $0.8 million higher, respectively, than the period ended December 23, 2010. The decrease in lease operating expenses on an equivalent basis was primarily related to the lower operating costs of the wells acquired from HEC. On an equivalent basis, the lease operating expense for the wells acquired from HEC was $7.50 per Boe during the period ended December 23, 2010 as compared to the lease operating expense for BCEC's wells which was $16.02 per Boe during the period ended December 23, 2010.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $4.4 million, or 303%, to $5.9 million for the year ended December 31, 2011 from $1.5 million for the period ended December 23, 2010 and increased on a Boe basis from $1.97 to $3.86. The increase was primarily related to a 106% increase in production volumes and a 19% increase in realized prices per Boe during the year ended December 31, 2011 as compared to the period ended December 23, 2010, and an increase in ad valorem tax of $2.4 million due to higher assessment values. The period ended December 23, 2010 does not include HEC severance and ad valorem tax, which were $0.8 million. The increase in severance and ad valorem taxes on a Boe basis for the year ended December 31, 2011 as compared to the period ended December 23, 2010 was primarily related to higher ad valorem taxes of $2.4 million and true-ups of estimated severance taxes based on Colorado severance tax returns for 2009 and 2010 that were filed during April of the subsequent year. The revision of estimated severance taxes based on the final Colorado severance tax returns resulted in a decrease in severance tax expense in 2010 and an increase in severance tax expense in 2011.

General and administrative. Our general and administrative expense increased $9.2 million, or 110%, to $17.6 million for the year ended December 31, 2011 from $8.4 million for the period ended December 23, 2010. The period ended December 23, 2010 does not include HEC's general and administrative expenses, which were $0.6 million. During the year ended December 31, 2011 wages and benefits and legal and professional services fees were $2.1 million and $2.0 million, respectively, higher than the previous period. The increase in wages and benefits is related to increased head count and $1.1 million of the increase in legal and professional services fees were related to investigations and transactions not consummated. In connection with our IPO, the Company distributed 243,945 fully vested shares of common stock previously held in trust to our employees and recorded a $4.1 million stock compensation charge. In addition, the Company distributed the remaining 3,400 shares of our former Class B common stock to our employees. In connection with our IPO, all issued and outstanding shares of our former Class B Common Stock converted into 437,787 shares of restricted common stock, vesting over a three year period and we recorded a $0.1 million stock compensation charge. We expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2012, 2013, and 2014 of approximately $2.5 million, $2.5 million, and $2.3 million, respectively, assuming no forfeitures.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $15.4 million, or 122%, to $28.0 million for the year ended December 31, 2011 from $12.6 million for the period ended December 23, 2010. This increase was the result of a 106% increase in production and the step up in basis that was recorded in oil and gas properties as a result of our Corporate Restructuring. In connection with our Corporate Restructuring, all of our oil and gas Fields were adjusted to fair value based on each Field's discounted future net cash flows, which resulted in basis increases to the Mid-Continent and Rocky Mountain Fields with corresponding decreases to the California Fields. Our depreciation, depletion and amortization expense per Boe increased by $1.38, or 8%, to $18.27 for the year ended December 23, 2011 as compared to $16.89 for the period ended December 23, 2010.

Exploration. Our exploration expense increased $0.7 million, or 286%, to $0.9 million for the year ended December 31, 2011 from $0.2 million in the period ended December 23, 2010. The increase in exploration expense was primarily related to 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.

Impairment of Proved Properties. The Company recorded $0.6 million of proved property impairments in one non-core Field in southern Arkansas for the year ended December 31, 2011. The impairment of the non-core Field in Southern Arkansas was related to the loss of a lease. There were no impairments of proved properties for the period ended December 23, 2010.

Interest expense. Our interest expense decreased $14.0 million, or 78%, to $4.0 million for the year ended December 31, 2011 from $18.0 million for the period ended December 23, 2010. The decrease resulted from the application of $182 million of cash proceeds from our Corporate Restructuring to repay the second lien term loan, the senior subordinated notes and a related party note payable, and to repay $29 million of principal under our credit facility on December 23, 2010. Average debt outstanding for the year ended December 31, 2011 was $95.3 million as compared to $215.3 million for the period ended December 23, 2010.

Realized gain (loss) on settled commodity derivatives. Realized gains on oil and gas hedging activities decreased by $8.9 million from a gain of $5.9 million for the period ended December 23, 2010 to a loss of $3.0 million for the year ended December 31, 2011. Because we assumed a derivative in a

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liability position in 2008, our realized gain was higher by $4.8 million upon the settlement of this portion of the assumed derivative in the period ended December 23, 2010. The decrease from a realized cash hedge gain to a loss period over period was primarily related to commodity prices that were 19% higher during the year ended December 31, 2011 as compared to the period ended December 23, 2010.

Income Tax Expense. Our predecessor, BCEC, was not subject to federal and state income taxes. As a result of our Corporate Restructuring, we were organized as a Delaware corporation subject to federal and state income taxes. During the year ended December 31, 2011, the estimated effective 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 $2.4 million with an additional $10.5 million incurred for federal and state income taxes for the year ended December 31, 2011 for a total deferred income tax expense in our consolidated statement of operations of $12.9 million. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. All income taxes for the year ended December 31, 2011 were deferred.

Change in fair value of warrant put option. The fair value of the warrant put option decreased $34.3 million, or 100%, to $0 for the year ended December 31, 2011 from a gain of $34.3 million for the period ended December 23, 2010. The decrease resulted from the exercise of the warrants on December 23, 2010 in connection with our Corporate Restructuring.

Accretion of debt discount. Our expense for accretion of debt discount decreased $8.9 million, or 100%, to $0 for the year ended December 31, 2011 from $8.9 million for the period ended December 23, 2010. The decrease resulted from the retirement of BCEC's senior subordinated notes on December 23, 2010 in connection with our Corporate Restructuring.

Results for Discontinued Operations

During June of 2012, the Company began marketing, with an intent to sell, all of our 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 these properties qualifies for discontinued operations accounting and these assets are presented as discontinued operations in the Company's statements of operations.

The operating results before income taxes for our California properties for the year ended December 31, 2012 were net revenues, operating expenses, and loss from discontinued operations of $5.4 million, $6.3 million, and $0.9 million, respectively, as compared to net revenues, operating expenses, and loss from discontinued operations of $6.7 million, $10.3 million, $3.6 million, for the year ended December 31, 2011. Operating expenses for the year ended December 31, 2012 included impairments in the amount of $1.6 million. Sales volumes for the years ended December 31, 2012 and 2011 were 53.7 MBbls and 66.1 MBbls, respectively.

The operating results before income taxes for our California properties for the year ended December 31, 2011 were net revenues, operating expenses, and loss from discontinued operations of $6.7 million, $10.3 million, and $3.6 million, respectively, as compared to net revenues, gain on the sale of the Jasmin property, operating expenses, and gain from discontinued operations of $4.8 million, $4.1 million, $4.7 million, and $0.1 million for the period ended December 23, 2010. 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 and period ended December 23, 2010 were 66.1 MBbls and 67.6 MBbls, respectively.

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See Note 4 to our consolidated financial statements included in Item 8 of Part II of this Annual Report on Form 10-K.

Liquidity and Capital Resources

Our primary sources of liquidity to date have been proceeds from our initial public offering, Corporate Restructuring, capital contributions from investors, borrowings under our credit facility and cash flows from operations and proceeds from the sale of non-core properties. Our primary use of capital has been for the acquisition and development of oil and natural gas properties.

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.

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 and will pay approximately $12 million on July 31st of each of the next four years. These future payments are secured by a letter of credit which reduced our availability under the borrowing base by $48 million as of December 31, 2012.

On April 6, 2012, the administrative agent under our credit facility was changed to KeyBank, National Association. On May 8, 2012, we entered into an amendment with the lenders under our credit facility to, among other things, and (i) increase our credit facility to $600 million, and (ii) make changes in the covenant applicable to hedging to allow greater flexibility for management to implement comprehensive hedging plans to adequately protect our operations and capital budgets. On October 30, 2012 our borrowing base was increased to $325 million, and as of December 31, 2012, we had $158.0 million outstanding, $48.0 million of letters of credit issued, and $119.0 million of borrowing capacity available under our credit facility. Our weighted-average interest rate on borrowings from our credit facility was 4.06% during the year ended December 31, 2012.

On December 15, 2011 the Company sold 10,000,000 shares of our common stock in our IPO at $17.00 per share, less $1.105 per share for underwriting discounts and commissions. Other expenses related to the issuance and distribution of these shares were approximately $3 million.

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."

We believe that the combination of our cash flow from operating activities, potential access to debt and capital markets, our current liquidity level and our ability to modify our future capital expenditure programs, will allow us to comply with all of our debt covenants, and meet the obligations from our ongoing operations.

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

	Year Ended December 31, 2012	Year Ended December 31, 2011	Period from Inception (December 23, 2010 to December 31, 2010)	Period Ended December 23, 2010
			(in thousands)	
Financial Measures:				
Net cash provided by operating activities	$ 156,910	$ 57,603	$ 1,633	$ 22,759
Net cash provided by (used in) investing activities	(304,551)	(158,902)	(817)	(32,127)
Net cash provided by (used in) financing activities	149,819	103,389		9,297
Cash and cash equivalents	4,268	2,090		2,450
Acquisitions of oil and gas properties	13,920	1,810		1,066
Exploration and development of oil and gas properties and investment in gas processing facility	297,114	156,871	817	34,728

Cash flows provided by operating activities

Net cash provided by operating activities was $156.9 million for the year ended December 31, 2012, compared to $57.6 million provided by operating activities for the year ended December 31, 2011. The increase in cash flows from operating activities resulted primarily from an increase in revenues from increased production. Cash provided by changes in working capital for the year ended December 31, 2012 was $0.7 million as compared to cash utilized by changes in working capital in the amount of $7.0 million for the comparable period during 2011. The increase in working capital of $0.7 million for the year ended December 31, 2012 is comprised primarily of increases in accounts receivable and prepaid expenses and other assets in the amount of $21.9 million offset by an increase in accounts payables and accrued liabilities (exclusive of capital accruals) of $22.8 million due primarily to timing of accounts payable check distributions.

Net cash provided by operating activities was $57.6 million for the year ended December 31, 2011, compared to $22.8 million provided by operating activities for the period ended December 23, 2010. The increase in operating activities resulted primarily from an increase in revenues, increased production, and increased commodity prices offset by cash utilized in connection with changes in working capital when comparing the periods. Cash utilized by changes in working capital for the year ended December 31, 2011 was $7.0 million as compared to $5.8 million that was provided by changes in working capital for the comparable period during 2010. Decreases in working capital of $7.0 million for the year ended December 31, 2011 is comprised primarily of increases in accounts receivable of $11.7 million offset by an increase in accounts payables and accrued liabilities (exclusive of capital accruals) of $6.0 million due primarily to timing of accounts payable check distributions.

Cash flows provided by (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, 2012 was $304.6 million, compared to $158.9 million cash used in investing activities for the year ended December 31, 2011. The increase was primarily due to expenditures of $13.9 million for the acquisition of oil and gas properties, $281.3 million for exploration and development of oil and gas properties, $15.8 million for natural gas plant costs, and $3.1 million for non oil and gas property additions, partially offset by $9.3 million of proceeds received for the sale of non core oil and gas properties in California.

For the year ended December 31, 2011, net cash used in investing activities was $158.9 million for the development of oil and natural gas properties, including $22.7 million for a natural gas plant and other facilities and $1.8 million for the acquisition of oil and gas properties. For the period ended December 23, 2010, excluding our Corporate Restructuring, net cash used in investing activities was $32.1 million, of which we spent approximately $1.1 million on acquisitions, $34.7 million for the exploration and development of oil and gas properties including $4.0 million for a natural gas plant and other facilities, advanced $3.7 million to fund HEC's exploration and development program, offset by the receipt of proceeds in the amount of $7.5 million for the sale of the Jasmin Field. In connection with our Corporate Restructuring, $59 million in cash along with common stock valued at $21.1 million was used to acquire HEC.

Cash flows provided by (used in) financing activities

Net cash flow provided by financing activities for the year ended December 31, 2012 was $149.8 million primarily related to revolver borrowings in the amount of $151.4 million partially offset by $0.5 million that was spent to satisfy employee tax withholdings for restricted stock that vested during the year and deferred financing costs in the amount of $1.1 million. Net cash flow provided by financing activities for the year ended December 31, 2011 was $103.4 million primarily related to the sale of common stock, net of offering expenses, in the amount of $155.9 million offset by a net reduction in debt from payments on our credit facility in the amount of $48.8 million. Cash used for deferred financing costs was approximately $2.3 million and we spent $1.4 million to satisfy employee tax withholdings related to common stock that was granted during the period. Net cash provided by financing, excluding Corporate Restructuring, was $9.3 million for the period ended December 23, 2010, primarily related to net borrowings in the amount of $12.7 million offset by deferred financing charges in the amount of $3.4 million.

In connection with our Corporate Restructuring, we received net proceeds of approximately $265 million from the sale of shares of our common stock to West Face Capital and to certain clients of AIMCo. Proceeds from this transaction in the amount of $59 million along with common stock valued at $21.1 million was used to acquire HEC; $17.3 million of the proceeds were used for debt extinguishment penalties; and $182 million was used to retire BCEC's second lien term loan, the senior subordinated notes and a related party note payable, and to make a $29 million principal payment on BCEC's line of credit.

Credit facility

Senior Secured Revolving Credit Facility On April 6, 2012, the administrative agent under our credit facility was changed to Key Bank National Association. On May 8, 2012, we entered into an amendment with the lenders under our credit facility to, among other things, (i) increase our credit facility to $600 million, and (ii) make changes in the covenant applicable to hedging to allow greater flexibility for management to implement comprehensive hedging plans to adequately protect the Company's operations and capital budgets. The Revolver provides for interest rates plus an applicable margin to be determined based on 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, plus .75% to 1.75%.

Our borrowing base under the credit agreement, which was $325 million as of December 31, 2012, 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

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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, 2012, we had approximately $158 million outstanding under our credit facility. As of February 28, 2013, we had approximately $191.5 million outstanding under our credit facility. The credit facility matures on September 15, 2016. Amounts borrowed and repaid under the credit facility may be reborrowed. The credit facility may be used only to finance development of oil and gas properties, for working capital and for other general corporate purposes.

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

Interest under the credit facility is generally determined by reference to either, at our option:

- the London interbank offered rate, or LIBOR, for an elected interest period plus an applicable margin between 1.75% to 2.75%; or

- an alternate base rate (being the highest of the administrative agent's prime rate, the federal funds effective rate plus 0.5% or 3-month LIBOR plus 1.00%) plus an applicable margin between 0.75% and 1.75%.

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 credit facility at any time without premium or penalty (other than customary LIBOR breakage costs).

The credit facility contains various covenants limiting our ability to:

- grant or assume liens;

- incur or assume indebtedness;

- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;

- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;

- make certain distributions;

- make certain loans, advances and investments;

- engage in transactions with affiliates;

enter into sale and leaseback, take-or-pay or hydrocarbon prepayment transactions; or

enter into certain swap agreements.

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The credit facility 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 Credit Agreement) ("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, 2012, we were in compliance with these ratios. If an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity of the loan and exercise other rights and remedies.

The credit agreement 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 credit agreement), including the ownership by a "person" or "group" (as defined under the Securities and Exchange Act of 1934, as amended, but excluding certain permitted stockholders) directly or indirectly, of more than 35% of our common stock, other than certain of our current stockholders.

Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2012 (in thousands):

	Payment by Period				
Contractual Obligation	**Total**	**1 Year or Less**	**2 - 3 Years**	**4 - 5 Years**	**More Than 5 Years**
Wattenberg Field Lease Acquisition	$ 48,000	$ 12,000	$ 24,000	$ 12,000	$
Credit facility(1)	158,000			158,000	
Operating leases(2)	6,989	1,375	3,037	2,109	468
Asset retirement obligations(3)	7,734	400	452		6,882
Total	$ 220,723	$ 13,775	$ 27,489	$ 172,109	$ 7,350

(1) Amount excludes interest on our credit facility as both the amount borrowed and the applicable interest rate is variable.

(2) See Note 8 to our consolidated financial statements for a description of operating leases.

(3) Amount represents our estimate of future retirement obligations on a discounted basis unless otherwise noted. Because these costs typically extend many years into the future, management

prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. The $0.4 million included in the one year or less category is not discounted and is included in accounts payable and accrued expenses as of December 31, 2012.

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 2 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 of the unproved lease acquisition costs is recorded as impairment expense in the statement of operations 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. 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.

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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 Statement of Operations.

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

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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. Realized gains and realized losses from the settlement of commodity derivative instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under Other Income (Expense) in our Consolidated Statement of Operations.

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 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 Statement of Operations.

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 is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

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

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realized upon ultimate settlement with the relevant tax authority. We did not have any uncertain tax positions as of the year ended December 31, 2012.

Recent accounting pronouncements

Goodwill. In December 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2010-28, "Intangibles Goodwill and Other: When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts" ("ASU 2010-28"). ASU 2010-28 requires step two of the goodwill impairment test to be performed when the carrying value of a reporting unit is zero or negative, if it is more likely than not that a goodwill impairment exists. The requirements of this update are effective for fiscal years beginning after December 15, 2010. The adoption of this new guidance did not have an impact on our financial position, cash flows or results of operations.

Business combinations. In December 2010, the FASB issued ASU 2010-29, "Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations" ("ASU 2010-29"). ASU 2010-29 clarifies that when presenting comparative pro forma financial statements in conjunction with business combination disclosures, revenue and earnings of the combined entity should be presented as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period. In addition, the update requires a description of the nature and amount of material, nonrecurring pro forma adjustments included in pro forma revenue and earnings that are directly attributable to the business combination. This update is effective prospectively for business combinations that occur on or after the beginning of the first annual reporting period after December 15, 2010. As ASU 2010-29 relates to disclosure requirements, there was no impact on our financial position, cash flows or results of operations.

Inflation

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, 2012, 2011 and 2010. 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.

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 Prices. 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 prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2012 would have been lower by approximately $161.6 million.

Our primary commodity risk management objective is to reduce volatility in our cash flows. Management makes recommendations on hedging that are approved by the board of directors before implementation. We enter into hedges for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only certain 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 hedging activities, 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 hedging arrangements are concentrated with five counterparties, four 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 hedge derivatives, if owed by us, generally up to three business days before we receive market price cash payments from our customers. This could have a material adverse effect on our cash flows for the period between hedge settlement and payment for revenues earned.

The following table provides a summary of derivative contracts as of December 31, 2012:

Settlement Period	Derivative Instrument	Total Notional Amount (BBL/Mmbtu)	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability)
Oil					
2013	Collar	890,616	88.92	103.00	1,727,192
	Swap	1,035,417	88.54		(4,864,853)
2014	Collar	672,000	85.00	95.50	(1,235,168)
	Swap	228,000	90.80		(308,287)
Gas					
2013	Swap	154,806	6.40		450,872

Interest Rates. At February 28, 2013, we had $191.5 million outstanding 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. Based on borrowings outstanding at February 28, 2013, a 100 basis point change in interest rates would change our annualized interest expense by approximately $1.9 million.

Counterparty and customer credit risk. In connection with our hedging activity, we have exposure to financial institutions in the form of derivative transactions. Four lenders under our credit facility are currently four of the five 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. See "Item 1. Business Principal Customers" for further detail about our

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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, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services and pipelines 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 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, 2012 and 2011, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2012 and 2011 and the period from its inception (December 23, 2010) to December 31, 2010, and the Bonanza Creek Energy Company, LLC and subsidiaries (predecessor) consolidated statements of operations and cash flows for the period January 1, 2010 to December 23, 2010. 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, 2012 and 2011, and the results of their operations and their cash flows for the years ended December 31, 2012 and 2011 and for the period December 23, 2010 to December 31, 2010, and the results of the predecessor's operations and cash flows for the period January 1, 2010 to December 23, 2010, 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, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 14, 2013 expressed an unqualified opinion on the effectiveness of Bonanza Creek Energy, Inc.'s internal control over financial reporting.

/s/ Hein & Associates LLP

Denver, Colorado
March 14, 2013

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BONANZA CREEK ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,267,667	$ 2,089,674
Accounts receivable:		
Oil and gas sales	38,600,436	17,850,719
Other	5,484,620	5,696,825
Prepaid expenses and other	3,031,815	1,868,016
Inventory of oilfield equipment	1,740,934	3,324,368
Derivative asset	2,178,064	1,297,403
Total current assets	55,303,536	32,127,005
OIL AND GAS PROPERTIES using the successful efforts method of accounting		
Proved properties	811,000,239	547,878,188
Unproved properties	72,928,364	15,848,703
Wells in progress	75,031,806	23,783,142
	958,960,409	587,510,033
Less: accumulated depreciation, depletion and amortization	(89,669,725)	(26,759,043)
	869,290,684	560,750,990
NATURAL GAS PLANT	73,087,603	56,910,232
Less: accumulated depreciation	(3,403,817)	(1,286,129)
	69,683,786	55,624,103
PROPERTY AND EQUIPMENT	5,089,795	1,983,037
Less: accumulated depreciation	(890,093)	(128,731)
	4,199,702	1,854,306
OIL AND GAS PROPERTIES HELD FOR SALE, LESS ACCUMULATED DEPRECIATION AND DEPLETION	582,388	9,895,508
LONG-TERM DERIVATIVE ASSET		678,474
OTHER ASSETS	3,429,711	3,418,626
TOTAL ASSETS	$ 1,002,489,807	$ 664,349,012
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 72,850,272	$ 27,068,326
Oil and gas revenue distribution payable	12,552,655	6,185,983
Contractual obligation for land acquisition	11,999,877	
Derivative liability	5,200,202	5,276,633
Total current liabilities	102,603,006	38,530,942
LONG-TERM LIABILITIES:		
Bank revolving credit	158,000,000	6,600,000
Contractual obligation for land acquisition	33,271,631	
Ad valorem taxes	11,179,370	3,014,023
Derivative liability	1,208,106	2,579,175
Deferred income taxes, net	110,376,606	79,603,633

Asset retirement obligations	7,333,584	6,039,723
TOTAL LIABILITIES	423,972,303	136,367,496
COMMITMENTS AND CONTINGENCIES (Notes 8 and 11)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $.001 par value, 25,000,000 shares authorized, outstanding		
Common stock, $.001 par value, 225,000,000 shares authorized, 40,115,536 and 39,477,584 issued and outstanding, respectively	40,116	39,478
Additional paid-in capital	519,425,356	515,412,583
Retained earnings	59,052,032	12,529,455
Total stockholders' equity	578,517,504	527,981,516
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,002,489,807	$ 664,349,012

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES AND PREDECESSOR

CONSOLIDATED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME

	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2012	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2011	Bonanza Creek Energy, Inc. For the Period From Inception (December 23, 2010) to December 31, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Period January 1, 2010 to December 23, 2010
NET REVENUES:				
Oil and gas sales	$ 231,205,241	$ 105,723,993	$ 1,620,192	$ 43,506,084
OPERATING EXPENSES:				
Lease operating	30,695,192	18,252,963	419,100	11,947,925
Severance and ad valorem taxes	13,673,814	5,918,566	66,460	1,467,477
Exploration	10,714,918	876,971		226,452
Depreciation, depletion and amortization	66,201,942	28,014,077	435,552	12,598,429
Impairment of oil and gas properties	611,355	623,039		
General and administrative (including $4,482,611, $4,436,794,$, and $, respectively, of stock compensation)	31,404,970	17,612,943	323,545	8,374,875
Cancelled private placement				2,378,468
Total operating expenses	153,302,191	71,298,559	1,244,657	36,993,626
INCOME FROM OPERATIONS	77,903,050	34,425,434	375,535	6,512,458
OTHER INCOME (EXPENSE):				
Realized gain (loss) on settled commodity derivatives	(725,382)	(3,024,136)	(46,742)	5,918,702
Interest expense	(4,132,955)	(4,017,230)	(57,656)	(18,000,796)
Unrealized gain (loss) in fair value of commodity derivatives	1,649,687	225,393	(514,627)	(7,604,742)
Other income (loss)	(132,526)	(110,276)		19,173
Write off of deferred financing costs				(1,663,167)
Change in fair value of warrant put option				34,344,894
Accretion of debt discount				(8,861,955)
Total other income (expense)	(3,341,176)	(6,926,249)	(619,025)	4,152,109
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	74,561,874	27,499,185	(243,490)	10,664,567
Current income taxes	(531,773)			
Deferred income tax (expense) benefit (Note 10)	(29,459,500)	(12,890,328)	89,775	*
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 44,570,601	$ 14,608,857	$ (153,715)	$ 10,664,567
DISCONTINUED OPERATIONS (Note 4)				
(Loss) income from operations associated with oil and gas properties held for sale	(926,671)	(3,609,764)	(12,689)	63,962
Gain on sale of oil and gas properties	4,192,120			4,055,153
Income tax (expense) benefit	(1,313,473)	1,692,088	4,678	*
Income (loss) from discontinued operations	1,951,976	(1,917,676)	(8,011)	4,119,115
NET INCOME (LOSS)	$ 46,522,577	$ 12,691,181	$ (161,726)	$ 14,783,682
COMPREHENSIVE INCOME (LOSS)	$ 46,522,577	$ 12,691,181	$ (161,726)	$ 14,783,682

BASIC AND DILUTED INCOME PER SHARE					
Income from continuing operations	$	1.12	0.49		*
Income (loss) from discontinued operations	$	0.05	(0.06)		*
Net income per common share	$	1.17	0.43		*
WEIGHTED AVERAGE NUMBER OF SHARES OF COMMON STOCK BASIC AND DILUTED:		39,787,565	29,576,442	29,122,521	*

* Bonanza Creek Energy Company, LLC was a limited liability company. See note 1 to Bonanza Creek Energy, Inc.'s annual financial statements.

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

FOR THE PERIOD FROM INCEPTION (DECEMBER 23, 2010) TO DECEMBER 31, 2012

	Common Stock		Class B	Additional Paid-In	Accumulated	
	Shares	Amount	Shares	Capital	Deficit	Total
BALANCES at December 23, 2010				$	$	$
Contribution of capital	29,122,521	$ 29,123	7,500	356,513,012		356,542,135
Net (loss)					(161,726)	(161,726)
BALANCES at December 31, 2010	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 at 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 at December 31, 2012	40,115,536	$ 40,116		$ 519,425,356	$ 59,052,032	$ 578,517,504

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BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES AND PREDECESSOR

CONSOLIDATED STATEMENT OF CASH FLOWS

	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2012	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2011	Bonanza Creek Energy, Inc. For the Period From Inception December 23, 2010 to December 31, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Period January 1, 2010 to December 23, 2010
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ 46,522,577	$ 12,691,181	$ (161,726)	$ 14,783,682
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization	68,444,803	31,507,596	506,307	14,225,309
Change in unrealized loss on derivative liability assumed				(4,811,518)
Deferred income taxes	30,772,973	11,198,240	(94,453)	
Impairment of oil and gas properties	2,259,545	4,067,023		
Stock-based compensation	4,482,611	4,436,794		
Exploration	8,378,612			
Amortization of deferred financing costs	700,162	1,004,225	15,589	1,641,209
Write off of deferred financing costs				1,663,167
Amortization of deferred novation fees				403,676
Accretion of debt discount				8,861,955
Accretion of contractual obligation for land acquisition	317,209			
Payment in kind interest				10,991,527
Gain on sale of oil and gas properties	(4,192,120)			(4,055,153)
(Increase) in outstanding warrants				(34,344,894)
Valuation (increase) decrease in commodity derivatives	(1,649,687)	(225,393)	514,627	7,604,742
Other	167,851	(40,368)		42,758
(Increase) decrease in operating assets:				
Accounts receivable	(20,737,512)	(11,712,123)	(2,104,097)	(726,157)
Prepaid expenses and other assets	(1,163,799)	(1,164,953)		27,358
(Decrease) increase in operating liabilities:				
Accounts payable and accrued liabilities	22,768,732	5,996,440	(309,076)	6,495,772
Settlement of asset retirement obligations	(161,787)	(155,558)		(44,758)
Net cash provided by operating activities	156,910,170	57,603,104	(1,632,829)	22,758,675
CASH FLOWS FROM INVESTING ACTIVITIES:				
Acquisition of oil and gas properties	(13,920,184)	(1,809,657)		(1,066,277)
Exploration and development of oil and gas properties	(281,326,110)	(134,183,772)	(817,362)	(30,733,263)
Natural gas plant capital expenditures	(15,787,631)	(22,687,197)		(3,994,304)
Proceeds from note receivable		986,906		103,903
Proceeds from sale of properties	9,336,898			7,475,654
Decrease in restricted cash	252,580			250,000
Increase in receivable from Holmes Eastern Company, LLC				(3,665,703)
Additions to property and equipment non oil and gas	(3,106,758)	(1,208,755)		(497,073)
Net cash used in investing activities	(304,551,205)	(158,902,475)	(817,362)	(32,127,063)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Increase in bank revolving credit and subordinated debt	151,400,000	108,100,000		118,200,000
Payment on bank revolving credit and subordinated debt		(156,900,000)		(105,500,000)
Proceeds from sale of Bonanza Creek Energy, Inc. common stock		155,878,320		
Offering costs related to sale of common stock	(2,952)			
Common stock returned for tax withholdings	(466,904)	(1,405,188)		
Deferred financing costs	(1,111,116)	(2,284,087)		(3,402,934)

Net cash (used in) provided by financing activities		149,819,028		103,389,045				9,297,066
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		2,177,993		2,089,674		(2,450,191)		(71,322)
CASH AND CASH EQUIVALENTS:								
Beginning of period		2,089,674				2,450,191		2,521,513
End of period	$	4,267,667	$	2,089,674	$		$	2,450,191
SUPPLEMENTAL CASH FLOW DISCLOSURE:								
Cash paid for interest	$	2,914,095	$	3,101,074	$		$	5,410,127
Cash paid for income taxes	$	400,000	$		$		$	
Value of stock issued to acquire BCEC and HEC, 7,966,387 shares at $12.52 per share	$		$		$	99,613,966	$	
Changes in working capital related to drilling expenditures and property acquisition	$	37,545,233	$	9,555,592	$		$	2,723,130
Contractual obligation for land acquisition	$	45,271,508	$		$		$	

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012

1. ORGANIZATION AND BUSINESS:

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, 2012, the Company's assets and operations are concentrated primarily in Southern Arkansas and in the Wattenberg Field in the Rocky Mountains. On December 23, 2010, BCEI, a Delaware Subchapter C corporation that was formed on December 2, 2010 (the "Company" or "BCEI"), participated in the following transactions which were accomplished simultaneously:

(1) The contribution by Bonanza Creek Energy Company, LLC ("BCEC" or "Predecessor") of all of its ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary) to BCEI and the assumption by BCEI of BCEC's remaining debt (as described below) in exchange for a 21.55% ownership interest of BCEI. BCEC had no other significant assets or subsidiaries at such time. BCEC was an operating oil and gas company that was initially founded in 2006;

(2) The sale of $265 million of Class A common stock of BCEI which constituted an ownership interest of 72.68% of BCEI to Project Black Bear LP ("Black Bear"), an entity advised by West Face Capital Inc. ("West Face Capital"), and to certain clients of Alberta Investment Management Corporation ("AIMCo"); and

(3) The exchange of shares of 5.77% of BCEI's Class A common stock together with $59 million in cash (which came from the $265 million sale of common stock of BCEI described in (2) above), for all of the equity interests of Holmes Eastern Company, LLC, a Delaware limited liability company ("HEC"), that was majority owned by a minority member of Bonanza Creek Oil Company, LLC ("BCOC"). BCOC was the predecessor of BCEC and owned 29.9% of BCEC on a fully diluted basis at the time of such transaction. HEC was initially formed in 2009 and has been an operating oil and gas exploration and production business since its formation.

The BCEC ownership (21.55%) of BCEI was subsequently distributed to or for the benefit of BCEC's members based on management's estimate of fair value of the BCEI shares received by BCEC to holders of the equity interests of BCEC in connection with the redemption of BCEC's equity and BCEC's dissolution to or for the benefit of:

(1) BCOC in the amount of 5.5% (for its Class A Units of BCEC);

(2) D.E. Shaw Laminar Portfolios, L.L.C. ("Laminar") in the amount of 12.91% (for its Class A Units of BCEC); and

(3) The management and employees of BCEC, in the amount of 3.14% (for their Class B Units of BCEC).

Cash proceeds of approximately $182 million were used to retire BCEC's second lien term loan, senior subordinated notes and a related party note payable, and to reduce the outstanding principal balance on BCEC's bank revolving credit facility by $29 million thereby reducing the balance outstanding to approximately $55.4 million as of December 31, 2010. This loan at the same time was assumed by BCEI.

The Company completed its initial public offering of common stock in December 2011 (the "IPO") pursuant to which 10,000,000 shares of common stock were sold.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Principles of Consolidation 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 Company, LLC and HEC. All significant intercompany accounts and transactions have been eliminated.

Fair Value of Financial Instruments The Company's financial instruments consist of trade receivables, trade payables, accrued liabilities, a revolving credit facility, and derivative instruments. Trade receivables, trade payables and accrued liabilities are carried at cost and approximate fair value due to the short term nature of these accounts. Our revolving credit facility has a variable interest rate so it approximates fair value. Derivative instruments are adjusted to fair value every accounting period. The book value of the contractual obligation for land acquisition approximates fair value due to it being discounted at a market based interest rate.

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.

Accounts Receivable Trade accounts receivable are recorded at net realizable value which is estimated to be fair value at December 31, 2012 and 2011. If the financial condition of the Company's customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. Delinquent trade accounts receivable are charged against the allowance for doubtful accounts once collectability has been determined.

The Company's crude oil and natural gas receivables are generally collected within two months. 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.

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 average cost or market which as of December 31, 2012 and 2011 approximated fair value.

Oil and Gas Producing Activities The Company follows the successful efforts method of accounting for its oil and gas properties. 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 the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs will be charged to expense. The costs of development wells will be capitalized whether productive or nonproductive. Costs incurred to maintain wells and related equipment and lease and well operating costs are charged to expense as incurred. Gains and losses arising from sales of properties will be included in income. However, sales that do not significantly affect a Field's unit-of-production depletion rate will be accounted for as

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

normal retirements with no gain or loss recognized. Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties 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 will be 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 Decmber 31, 2012, the Company recorded $1.7 million of proved property impairments on the legacy assets in California and $0.6 million of proved property impairments in one non-core field in Southern Arkansas. For the year ended December 31, 2011, the Company recorded $3.5 million of proved property impairments on the Company's legacy California assets and $0.6 million of proved property impairment in one non-core Field in Southern Arkansas. 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. These calculations involved significant unobservable inputs and, therefore, they are Level 3 fair value estimates.

The Company assesses its 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.

The Company has 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. The Company considers the following factors in its assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under leases;
- its ability to actively manage and prioritize its capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- its ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- its ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

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

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. Refer also to Note 10 for additional information on the Company's asset retirement obligations.

Long-Lived Assets Long-lived assets to be held and used or disposed of other than by sale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used or disposed of other than by sale are recognized based on the fair value of the asset. Long-lived assets to be disposed of by sale are reported at the lower of their carrying amount or fair value less cost to sell.

Other Property an*d Equipment* Property and equipment are recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to ten years.

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. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. The Company has interests with other producers in certain properties in which case the Company uses the entitlement method to account for gas imbalances. Gas imbalances as of December 31, 2012 and 2011 were immaterial.

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 natural gas liquids ("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 outline 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 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.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

As of December 31, 2012, Lion Oil Trading & Transport and Plains Marketing accounted for 32% and 50%, respectively, of oil and natural gas sales. For the year ended December 31, 2011, Lion Oil Trading & Transport and Plains Marketing accounted for 35% and 45%, respectively, of oil and natural gas sales. For the year ended December 31, 2010 Lion Oil Trading & Transport and Plains Marketing accounted for 52% and 30%, respectively, of oil and natural gas sales.

Risks and Uncertainties Historically, oil and gas prices have experienced significant fluctuations and have been particularly volatile in recent years. Price fluctuations can result from variations in weather, levels of regional or national production and demand, availability of transportation capacity to other regions of the country and various other factors.

Oil and Gas Derivative Activities The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value.

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 as economic hedges. The contracts, which are generally placed with major financial institutions or with counter parties which management believes to be of high credit quality, may take the form of futures contracts, swaps or options. The oil and gas reference prices of these contracts are based upon oil and natural gas futures, which have a high degree of historical correlation with actual prices received by the Company.

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.

3. ACQUISITIONS:

On December 23, 2010, the Company completed the following transactions: (i) the sale of 21,166,134 shares of common stock for $12.52 per share; (ii) the issuance of 6,272,851 shares of common stock valued at $12.52 per share to the holders of BCEC in exchange for all of BCEC's ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary); and (iii) the acquisition of all of the ownership of HEC for approximately $59 million in cash and 1,683,536 shares of its common stock valued at $12.52 per share. As part of the transactions, the Company also retired debt of approximately $182 million for cash and paid approximately $17 million for debt extinguishment penalties assumed as part of the merger. Because the penalties for the extinguishment of debt were considered as part of the liabilities assumed, the penalties were allocated to the assets acquired and the liabilities assumed as part of the purchase price. Furthermore, a deferred tax liability was recorded based on the difference between the tax basis of the contributed assets and liabilities and

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

3. ACQUISITIONS: (Continued)

their fair value at an effective tax rate of approximately 37%. Fair value was allocated to the assets contributed and liabilities assumed as follows:

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Debt Extinguishment	Deferred Tax Adjustment	Bonanza Creek Energy, Inc.
Current assets, including cash and commodity derivatives	$ 10,917,445	$ 3,848,328	$	$	$ 14,765,773
Proved oil and gas properties	280,831,550	77,985,048	16,680,311	65,806,160	441,303,069
Unproved oil and gas properties	11,376,727		678,704	2,693,686	14,749,117
Wells in progress	5,782,885	1,786,917			7,569,802
Natural gas plant	31,840,475				31,840,475
Property and equipment	777,564	25,115			802,679
Other noncurrent assets, including commodity derivatives	5,357,346				5,357,346
Current liabilities, including commodity derivatives	(19,894,250)	(3,559,307)			(23,453,557)
Bank revolving credit	(84,400,000)		29,000,000		(55,400,000)
Senior subordinated notes, including pre-payment penalty of $14,327,348	(125,145,205)		125,145,205		
Second lien term loan, including pre-payment penalty of $3,031,667	(33,031,667)		33,031,667		
Note payable related party	(12,276,228)		12,276,228		
Commodity derivatives, noncurrent	(5,673,460)				(5,673,460)
Deferred income taxes, net				(68,499,846)	(68,499,846)
Other noncurrent liabilities, including asset retirement obligations	(5,917,784)	(901,479)			(6,819,263)
Value of common stock issued as consideration	$ 60,545,398	$ 79,184,622	$ 216,812,115	$	$ 356,542,135

Supplemental Pro Forma Results (unaudited) The following unaudited pro forma financial information represents the combined results for BCEI, BCEC and HEC for year ended December 31, 2010 as if the contribution and acquisition had occurred on January 1, 2010. The adjustment to depreciation, depletion and amortization assumes that the oil and gas property step up in basis occurred January 1, 2010.

The pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

3. ACQUISITIONS: (Continued)

had the acquisition been completed as of the dates presented, and should not be taken as representative of the future consolidated results of operations of the Company.

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Bonanza Creek Energy, Inc.	Pro Forma Adjustments	Bonanza Creek Energy, Inc.
Net revenues:					
Oil and gas sales	$ 43,506,084	$ 13,957,560	$ 1,620,192	$	$ 59,083,836
Operating expenses:					
Lease operating	11,947,925	2,010,187	419,100		14,377,212
Severance and ad valorem taxes	1,467,477	834,282	66,460		2,368,219
Exploration	226,452	19,234			245,686
Depreciation, depletion and amortization	12,598,429	3,005,888	435,552	2,815,872	18,855,741
General and administrative	8,374,875	639,598	323,545		9,338,018
Cancelled private placement	2,378,468				2,378,468
Total operating expenses	36,993,626	6,509,189	1,244,657	2,815,872	47,563,344
Income (loss) from operations	6,512,458	7,448,371	375,535	(2,815,872)	11,520,492
Other income (expense):					
Other income (loss)	19,173	(65,694)			(46,521)
Write-off of deferred financing costs	(1,663,167)				(1,663,167)
Change in fair value of warrant put option	34,344,894			(34,344,894)	
Amortization of debt discount	(8,861,955)			8,861,955	
Realized gain on settled commodity derivatives	5,918,702		(46,742)		5,871,960
Unrealized loss in fair value of commodity derivatives	(7,604,742)		(514,627)		(8,119,369)
Interest expense	(18,000,796)	(439,171)	(57,656)	17,234,623	(1,263,000)
Total other income (expense)	4,152,109	(504,865)	(619,025)	(8,248,316)	(5,220,097)
Income (loss) from continuing operations	10,664,567	6,943,506	(243,490)	(11,064,188)	6,300,395
(Loss) income from operations associated with oil and gas properties held for sale	63,962		(12,689)	(363,624)	(312,351)
Gain on sale of oil and gas properties	4,055,153				4,055,153
Income (loss) before taxes	$ 14,783,682	$ 6,943,506	$ (256,179)	$ (11,427,812)	$ 10,043,197

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 and will pay approximately $12 million on July 31st of each of the next four years. These future payments were discounted based on our effective borrowing rate to arrive at the purchase price of $57,000,000. These future payments are secured by a $48 million letter of credit as of December 31, 2012 and interest will be imputed on the future payments. The amount

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

3. ACQUISITIONS: (Continued)

secured by the letter of credit will be amended each year on July 31st to reflect the reduction in obligation.

4. 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 its intent to sell these properties qualifies for 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 related to these transactions. The carrying amounts of the major classes of assets and liabilities related to the operation of the remaining properties that are held for sale as of December 31, 2012 and December 31, 2011 are presented below:

	As of December 31, 2012	As of December 31, 2011
ASSETS HELD FOR SALE, NET:		
Oil and gas properties, successful efforts method:		
Proved properties	$ 1,721,265	$ 13,060,597
Unproved properties	629	32,013
Wells in progress	39,245	167,198
Total property and equipment	1,761,139	13,259,808
Less accumulated depletion and depreciation	(1,178,751)	(3,364,300)
Net property and equipment	$ 582,388	$ 9,895,508

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

4. DISCONTINUED OPERATIONS: (Continued)

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

	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2012	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2011	Bonanza Creek Energy, Inc. For the Period From Inception December 23, 2010 to December 31, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Period January 1, 2010 to December 23, 2010
NET REVENUES:				
Oil and gas sales	$ 5,410,806	$ 6,739,479	$ 125,223	$ 4,822,010
OPERATING EXPENSES:				
Lease operating	2,279,844	3,234,575	63,728	2,843,860
Severance and ad valorem taxes	127,041	169,705	3,429	153,018
Exploration	39,541	7,460		134,290
Depreciation, depletion and amortization	2,242,861	3,493,519	70,755	1,626,880
Impairment of proved properties	1,648,190	3,443,984		
TOTAL COSTS AND EXPENSES	6,337,477	10,349,243	137,912	4,758,048
(LOSS) INCOME FROM OPERATIONS ASSOCIATED WITH OIL AND GAS PROPERTIES HELD FOR SALE	$ (926,671)	(3,609,764)	$ (12,689)	$ 63,962

5. 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. As of December 31, 2012 and 2011 the certificates of deposit totaled approximately $245,000 and $645,000, respectively.

As of December 31, 2012 and 2011, the Company had approximately $3,185,000, and $2,774,000, respectively of unamortized deferred financing costs related to the bank revolving credit agreement that was retained by the Company.

	2012	2011
Certificates of deposit	$ 245,131	$ 645,000
Note receivable		
Deferred financing costs	3,184,580	2,773,626
	$ 3,429,711	$ 3,418,626

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

6. ACCOUNTS PAYABLE AND ACCRUED EXPENSES:

Accounts payable and accrued expenses contain the following:

	2012	2011
Drilling and completion costs	$ 51,698,682	$ 14,153,449
Accounts payable trade	10,049,131	4,976,979
Accrued general and administrative cost	5,078,059	1,713,708
Accrued initial public offering expenses		1,258,791
Lease operating expense	2,824,300	2,128,470
Accrued reclamation cost	400,000	400,000
Interest	219,494	17,965
Accrued oil and gas hedging	238,365	353,897
Production taxes and other	2,342,241	2,065,067
	$ 72,850,272	$ 27,068,326

7. SENIOR SECURED REVOLVING CREDIT FACILITY:

Senior Secured Revolving Credit Facility On May 8, 2012, the Company amended its senior secured revolving Credit Agreement, (the "Revolver") dated March 29, 2011, with a syndication of banks, including KeyBank National Association as the administrative agent and issuing lender, which provides for borrowings of up to $600 million. The Revolver provides for interest rates plus an applicable margin to be determined based on the London Interbank Offered Rate (LIBOR) or a bank base rate ("Base Rate"), at the Company's election. LIBOR borrowings bear interest at LIBOR plus 1.75% to 2.75% depending on the utilization level, and the Base Rate borrowings bear interest at the "Bank Prime Rate," as defined plus ..75% to 1.75%.

The Revolver had a $325 million borrowing base as of December 31, 2012 which is subject to semi-annual re-determinations in April and October of each year. The letter of credit that was issued to the Colorado State Board of Land Commissioners (see Note 3) reduced the borrowing base by approximately $48 million. The Revolver provides for commitment fees ranging from 0.375% to 0.50%, depending on utilization, and restricts, among other items, the payment of dividends, certain additional 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 ratio and a minimum debt coverage ratio, as defined. The Company was in compliance with these covenants as of December 31, 2012. The Revolver is collateralized by substantially all the Company's assets and matures on September 15, 2016. As of December 31, 2012 there was $158,000,000 outstanding and the company had $119,000,000 available under the line.

8. COMMITMENTS AND CONTINGENT LIABILITIES:

Contingent Liabilities From time to time, the Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. In accordance with ASC 450, *Contingencies*, 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

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

8. COMMITMENTS AND CONTINGENT LIABILITIES: (Continued)

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.

Environmental The Company is engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operations. Relative to the Company's acquisition of existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could fall upon the Company. Management believes its properties are operated in conformity with local, state and federal regulations. No claims have been made, nor is the Company aware of any uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations.

Legal Proceedings From time to time, the Company is subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, the Company's 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 the Company of which it is aware.

In June 2011, Frank H. Bennett, a co-manager of Bonanza Creek Oil Company, LLC ("BCOC"), Bonanza Creek Energy, LLC's ("BCEC") predecessor, and former chairman of BCEC, made a demand against Michael R. Starzer, our President and Chief Executive Officer, focusing on Mr. Starzer's handling of the operation, accounting and finances of BCOC and BCEC primarily during the 2005-2006 time period. Mr. Bennett's demands do not allege any wrongdoing by or claims against Bonanza Creek Energy, Inc. This matter was sent to arbitration in July 2011. An arbitration hearing commenced in July 2012 and concluded in October 2012. At the end of November 2012, the arbitration panel issued an order finding in favor of Mr. Starzer on all of the plaintiff's claims. This order is final and non-appealable, thus effectively and favorably terminating the claims asserted by Mr. Bennett. During the period from January 1, 2012 through December 31, 2012, the Company incurred approximately $3 million for legal fees and other expenses related to Mr. Bennett's claims.

Commitments The Company rents office facilities under various noncancelable operating lease agreements. The Company's noncancelable operating lease agreements result in total future minimum

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

8. COMMITMENTS AND CONTINGENT LIABILITIES: (Continued)

noncancelable lease payments are presented below. The Company also has principal payment requirements for its line of credit which is also presented below:

	Office Leases	Wattenberg Field Acquisition	Line of Credit	Total
2013	$ 1,375,056	$ 11,999,877		$ 13,374,933
2014	1,496,803	11,999,877		13,496,680
2015	1,539,865	11,999,877		13,539,742
2016	1,185,363	11,999,877	$ 158,000,000	171,185,240
2017 and thereafter	1,391,894			1,391,894
	$ 6,988,981	$ 47,999,508	$ 158,000,000	$ 212,988,489

9. STOCKHOLDERS' EQUITY:

Common Stock On December 15, 2011 the Company sold 10,000,000 shares of common stock in our initial public offering at $17.00 per share, less $1.105 per share for underwriting discounts and commissions. Other expenses related to the issuance and distribution of these shares were approximately $3 million.

On December 23, 2010 the Company issued 21,166,134 shares of common stock to West Face Capital and to certain clients of AIMCo at $12.52 per share. Also as part of the formation on December 23, 2010, BCEC contributed all of its ownership interest in Bonanza Creek Energy Operating Company, LLC to the Company for 6,272,851 shares of its common stock valued at $12.52 per share. In addition, on December 23, 2010, the Company issued 1,683,536 shares of its common stock valued at $12.52 per share to the majority owner of HEC and a member of Bonanza Creek Energy, Inc.'s management who also owned a minority interest of HEC (refer to Note 3).

Management Incentive Plan On December 23, 2010, the Company established the Management Incentive Plan (the "Plan" or "MIP") 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 is 10,000 and these shares were converted into 437,787 shares of restricted common stock upon completion of our initial public offering. The conversion rate was determined based on a formula factoring in the rate of return to the common stockholders. The 437,787 shares of common stock that were granted to employees were valued at $17.00 per share on the grant date and vest over a three-year period. Stock-based compensation expense of $2,501,000 and $122,000 was recorded during the years ended December 31, 2012 and 2011 and there was $4,465,000 of unrecognized compensation costs related to the unvested restricted common stock granted under the plan. That cost is expected to be recognized over a period of 2.0 years.

BCEC Management Incentive Plan In connection with the corporate restructuring described in Note 1, 317,142 shares of common stock of BCEI were designated for holders of BCEI's 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. As of December 31, 2012, 73,197 shares of BCEI common stock remain held in trust and designated for

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

9. STOCKHOLDERS' EQUITY: (Continued)

holders of BCEC's Class B units. When and if such shares are issued, they will be valued based on the market price of the Company's common stock on the grant date.

During 2012, the Company granted 703,246 shares of restricted common stock under its 2011 Long Term Incentive Plan (the "LTIP") to officers and certain key employees. For accounting purposes, these shares are valued at the closing price of our common stock on the grant date. These shares will vest annually in one-third increments over three years. Stock-based compensation expense of $1,715,000 was recorded during the year ended December 31, 2012 and there was $9,246,000 of unrecognized compensation costs as of December 31, 2012 related to the unvested restricted stock granted under the Plan. That cost is expected to be recognized over a period of 2.9 years. On August 3, 2012, the Company granted an aggregate of 16,626 shares of common stock under the LTIP to the four independent members of its Board of Directors for their 2011-2012 service. Stock-based compensation expense of $267,000 was recorded during the year ended December 31, 2012. On August 3, 2012, the Company granted an aggregate of 16,908 shares of common stock under the LTIP to the four independent members of its Board of Directors for their 2012-2013 service. These shares will vest immediately prior to the Company's 2013 Annual Meeting.

10. INCOME TAXES:

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

	2012	2011	2010
Current tax (expense) benefit			
Federal	$ (288,659)	$	$
State	(243,114)		
Deferred tax (expense) benefit	(30,772,973)	(11,198,240)	94,453
Total income tax (expense) benefit	$ (31,304,746)	$ (11,198,240)	$ 94,453

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

10. INCOME TAXES: (Continued)

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:

	2012	2011
Property and equipment	$ 132,932,511	$ 94,695,252
Net operating loss carryforward	(16,061,072)	(10,431,642)
AMT Credit	(288,659)	
AMT Credit State	(158,024)	
Stock compensation	(777,069)	(110,041)
Abandonment obligations	(2,981,012)	(2,293,919)
Derivative liability	(1,398,054)	(2,233,229)
Deferred deductions and other	(100,222)	(22,788)
State property, plant, equipment	(791,793)	
Total long-term liability	$ 110,376,606	$ 79,603,633

The Company has $43,806,000 of net operating loss carryovers for federal income tax purposes as of December 31, 2012, of which $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. The benefit of these excess tax deductions will not be recognized for financial statement purposes until the related deductions reduce taxes payable. Reconciliation of the Company's effective tax rate to the expected federal tax rate of 35% in 2012 and 34% in 2011 and 2010 is as follows:

	2012	2011	2010
Expected federal tax rate	35%	34%	34%
State income taxes	3.55%	3.98%	2.87%
Change in tax rate	1.67%	8.9%	
Effective tax rate	40.22%	46.88%	36.87%

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 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 resulting in a total deferred income tax expense in our consolidated statement of operations 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, resulting in a total deferred income tax expense in our consolidated statement of operations of $11.2 million.

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

11. ASSET RETIREMENT OBLIGATIONS:

The fair value of asset retirement obligation is recorded as a liability when incurred, which is typically at the time the assets are acquired or placed in service. Amounts recorded for the related assets are increased by a corresponding amount of these obligations. Prospectively, the liabilities are accreted for the change in their present value and the initial capitalized costs are depleted, depreciated and amortized over the productive lives of the related assets.

	2012	2011
Beginning of year	$ 6,039,723	$ 5,611,709
Additional liabilities incurred	1,448,063	1,308,122
Accretion expense	519,315	443,801
Obligations on properties sold	(511,730)	
Liabilities settled	(161,787)	(155,558)
Revisions to estimate		(1,168,351)
End of year	$ 7,333,584	$ 6,039,723

The downward revision to asset retirement obligation recorded during 2011 was related to revised costs to abandon a well and longer well life due to higher oil prices.

12. FAIR VALUE MEASUREMENTS:

The Company defines fair value under a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. A hierarchy for inputs is used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

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

Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or

Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

ASC 820 requires financial assets and liabilities 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 Company's commodity swaps are valued using a market approach based on several factors, including 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

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

12. FAIR VALUE MEASUREMENTS: (Continued)

designated as Level 3 within the valuation hierarchy, are also valued using a market approach, but are not validated by observable transactions with respect to volatility. As of December 31, 2012, three of the four counterparties in the Company's commodity derivative financial instruments are lenders on the Company's Senior Secured Revolving Credit facility (Note 7).

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, 2012 and 2011 by level within the fair value hierarchy:

	Fair Value Measurements Using		
December 31, 2012	**Level 1**	**Level 2**	**Level 3**
Commodity derivative assets	$	$ 450,872	$ 1,727,192
Commodity derivative liabilities	$	$ 5,173,140	$ 1,235,168

	Fair Value Measurements Using		
December 31, 2011	**Level 1**	**Level 2**	**Level 3**
Commodity derivative assets	$	$ 1,094,055	$ 881,822
Commodity derivative liabilities	$	$ 6,740,213	$ 1,115,595

The following table reflects the activity for the commodity derivatives measured at fair value using Level 3 inputs during the period from January 1, 2012 through December 31, 2012:

	Derivative Asset	**Derivative Liability**
Beginning balance	$ 881,822	$ 1,115,595
Net increase (decrease) in fair value	796,287	(3,239,647)
Net realized gain on settlement	(362,095)	527,766
New derivatives	411,178	2,831,454
Transfers in (out) of Level 3	0	0
Ending balance	$ 1,727,192	$ 1,235,168

The allocation of the purchase price to the assets acquired and the liabilities assumed of BCEC and HEC was determined using Level 3 inputs.

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 percent for the one year period ended December 31, 2012. 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 New York Mercantile Exchange ("NYMEX") strip pricing, adjusted for basis differentials. Future operating costs are also adjusted as deemed appropriate for these estimates.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

12. FAIR VALUE MEASUREMENTS: (Continued)

Asset Retirement Obligation Upon completion of wells and natural gas plants, the Company records an asset retirement obligation at fair value using Level 3 assumptions.

13. DERIVATIVES:

As of December 31, 2012, the Company's derivative commodity contracts are as follows:

Settlement Period	Derivative Instrument	Total Notional Amount (BBL/Mmbtu)	Average Floor Price	Average Ceiling Price
Oil				
2013	Collar	890,616	88.92	103.00
	Swap	1,035,417	88.54	
2014	Collar	672,000	85.00	95.50
	Swap	228,000	90.80	
Gas				
2013	Swap	154,806	6.40	

The table below contains a summary of all the Company's derivative positions reported on the consolidated balance sheet as of December 31, 2012:

Derivatives	Balance Sheet Location	Fair Value
Asset		
Commodity derivatives	Current derivative assets	$ 2,178,064
Liability		
Commodity derivatives	Current derivative liability	(5,200,202)
Commodity derivatives	Long-term derivative liability	(1,208,106)
Total net derivative liability		$ (4,230,244)

14. SUBSEQUENT EVENTS:

On February 5, 2013 13,825 shares of our common stock that were fully vested and held by the BCEC Investment Trust were distributed to former employees. For accounting purposes, these shares are 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 shares of our common stock that were fully vested and held by the BCEC Investment Trust were distributed to certain current employees. For accounting purposes, these shares are valued at the closing price of our common stock on the grant date which was $34.89 per share.

The Company acquired 960 net mineral acres in Weld County, Colorado for approximately $1,165,000 on March 12, 2013. Expirations for the leasehold occur in 2014 and 2015 with an option to extend on most of the acreage.

Subsequent events have been evaluated by management through the date of issuance of these financial statements.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

15. 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:

	2012	2011	2010
Unproved property acquisitions	$ 57,048,277	$ 1,131,599	$
Proved property acquisitions	1,794,822	762,701	
Development(a)	324,958,016	84,161,794	817,362
Gas plant capital expenditures	16,177,371	25,069,757	
Exploration	4,821,190	58,034,514	
Total	$ 404,799,676	$ 169,160,365	$ 817,362

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

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

	2012	2011	2010
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	974,000
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	$ 974,000

At December 31, 2012, the Company had capitalized $0 for exploratory wells in progress for a period of greater than one year.

16. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

In December 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. The Company adopted the rules effective December 31, 2010, and the rule changes, including those related to pricing and technology, are included in the Company's reserve estimates.

The estimate of proved reserves and related valuations for the years ended December 31, 2010, 2011, and 2012 were based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

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

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

16. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (Continued)

natural gas reserves for the period ended December 31, 2010 and the years ended December 31, 2011 and 2012 are as follows:

	Oil (MBbl)(1)	Natural Gas (MMcf)
Balance December 23, 2010		
Extensions and discoveries		
Purchases of minerals in place	22,398	62,926
Production	(19)	(42)
Revisions to previous estimates		
Balance December 31, 2010	22,379	62,884
Extensions and discoveries(a)	7,182	29,608
Purchases of minerals in place		
Production	(1,137)	(2,776)
Revisions to previous estimates(b)	(208)	3,266
Balance December 31, 2011	28,216	92,982
Extensions and discoveries(a)	12,016	50,667
Sales of minerals in place	(669)	
Production	(2,529)	(5,475)
Revisions to previous estimates(b)	(3,768)	(19,626)
Balance December 31, 2012	33,266	118,548
Proved developed reserves:		
December 23, 2010		
December 31, 2010	8,180	20,074
December 31, 2011	11,842	31,313
December 31, 2012	15,675	48,942
Proved undeveloped reserves:		
December 23, 2010		
December 31, 2010	14,199	42,810
December 31, 2011	16,374	61,669
December 31, 2012	17,591	69,606

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

(a)

At December 31, 2012, horizontal development in the Wattenberg Field, Rocky Mountain Region resulted in additions in extension and discoveries of 17,380 MBoe which is 85% of our total extension and discoveries addition 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.

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

16. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (Continued)

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.

(b)

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 100 MBoe resulted from a decrease in commodity price from $96.19 per Bbl WTI crude oil and $4.12 per MMBtu Henry Hub for the year ended December 31, 2011 to $94.71 per Bbl WTI and $2.757 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 the provisions of ASC Topic 932. Future cash inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on costs and assuming continuation of existing economic conditions.

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

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

	December 31, 2012	December 31, 2011	December 31, 2010
Future cash flows	$ 3,367,465	$ 2,887,010	$ 1,894,178
Future production costs	(1,037,537)	(805,466)	(572,553)
Future development costs	(684,160)	(514,256)	(351,392)
Future income tax expense	(298,201)	(252,265)	(182,725)
Future net cash flows	1,347,567	1,315,023	787,508
10% annual discount for estimated timing of cash flows	(664,126)	(648,837)	(412,854)
Standardized measure of discounted future net cash flows	$ 683,441	$ 666,186	$ 374,654

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

16. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED): (Continued)

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at period end. The effect of hedging transactions in place as of year-end on the future cash flows for the period ended December 31, 2010 and years ended December 31, 2011 and 2012 were immaterial.

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):

	2012	2011	2010
Beginning of period	$ 666,186	$ 374,654	$
Sale of oil and gas produced, net of production costs	(189,840)	(84,888)	(1,193)
Net changes in prices and production costs	(81,527)	123,154	
Extensions, discoveries and improved recoveries	310,595	204,000	
Development costs incurred	161,527	93,916	817
Changes in estimated development cost	(9,404)	(62,175)	(817)
Purchases of mineral in place			374,803
Sales of mineral in place	(14,909)		
Revisions of previous quantity estimates	(156,867)	8,113	
Net change in income taxes	(23,441)	(40,866)	249
Accretion of discount	79,398	46,158	1,012
Changes in production rates and other	(58,277)	4,120	(217)
End of period	$ 683,441	$ 666,186	$ 374,654

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2012, 2011, and 2010 were calculated using the first-day-of-the-month price inclusive of adjustments for quality and location.

	2012	2011	2010
Oil (per Bbl)	$ 91.04	$ 89.80	$ 74.93
Gas (per Mcf)	$ 3.78	$ 4.82	$ 4.81

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Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2012 (Continued)

17. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2012 and period ended December 31, 2011 (in thousands, except per share data):

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2012				
Oil and natural gas sales	$ 47,830,431	$ 51,455,094	$ 58,327,823	$ 73,591,893
Operating profit(1)	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 earnings (loss) per share	0.22	0.54	0.09	0.32
2011				
Oil and natural gas sales	$ 20,541,995	$ 24,151,668	$ 25,915,330	$ 35,115,000
Operating profit(1)	10,308,846	12,451,574	13,556,361	17,221,606
Net income (loss)	326,920	7,707,745	4,833,352	(176,836)
Basic and diluted earnings (loss) per share	0.01	0.26	0.17	(0.01)

(1) Oil and natural gas sales less lease operating expense, production taxes and depreciation, depletion and amortization and adjusted to reflect retrospective application of discontinued operations.

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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, 2012. 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, 2012, 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, 2012, 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. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2012, 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, 2012, which is included in the consolidated financial statements in Item 8 of Part II of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the quarter ended December 31, 2012 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, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Bonanza Creek Energy, Inc. and subsidiaries and the related consolidated statement of operations, stockholders' equity and cash flows for the year ended December 31, 2012 of Bonanza Creek Energy, Inc. and our report dated March 14, 2013 expressed an unqualified opinion.

/s/ Hein & Associates LLP

Denver, Colorado
March 14, 2013

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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 2013 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012.

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 2013 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012.

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 2013 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012.

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 2013 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012.

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 2013 Annual Meeting of Stockholders to be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012.

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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 March 14, 2013.

BONANZA CREEK ENERGY, INC.

By: /s/ MICHAEL R. STARZER

Michael R. Starzer,
President and Chief Executive Officer

March 14, 2013

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Michael R. Starzer, Wade E. Jaques and Christopher I. Humber 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: March 14, 2013	By:	/s/ MICHAEL R. STARZER
		Michael R. Starzer, *Director, President and Chief Executive Officer (Principal Executive Officer)*
Date: March 14, 2013	By:	/s/ GARY A. GROVE
		Gary A. Grove, *Director, Executive Vice President Engineering and Planning and Interim Chief Operating Officer*
Date: March 14, 2013	By:	/s/ WADE E. JAQUES
		Wade E. Jaques, *Vice President, Chief Accounting Officer, Controller and Treasurer (Principal Financial and Accounting Officer)*

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Date: March 14, 2013	By:	/s/ RICHARD J. CARTY
		Richard J. Carty, *Chairman of the Board*
Date: March 14, 2013	By:	/s/ MARVIN M. CHRONISTER
		Marvin M. Chronister, *Director*
Date: March 14, 2013	By:	/s/ KEVIN A. NEVEU
		Kevin A. Neveu, *Director*
Date: March 14, 2013	By:	/s/ GREGORY P. RAIH
		Gregory P. Raih, *Director*
Date: March 14, 2013	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 Company's Current Report on Form 8-K filed on December 22, 2011)
3.2	Second Amended and Restated Bylaws of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on December 22, 2011)
4.1	Form of Senior Debt Indenture (incorporated by reference to Exhibit 4.4 to the Company's Registration Statement on Form S-3 filed on January 14, 2013)
4.2	Form of Subordinated Debt Indenture (incorporated by reference to Exhibit 4.5 to the Company's Registration Statement on Form S-3 filed on January 14, 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 Company's Registration Statement on Form S-1 filed on June 7, 2011); as amended by 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 Company's Registration Statement on Form S-1 filed on June 7, 2011); 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 Company's Registration Statement on Form S-1/A filed on November 4, 2011); 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 Company's Quarterly Report on Form 10-Q filed on May 10, 2012); Amendment No. 4, dated as of July 31, 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 Company's Quarterly Report on Form 10-Q filed on August 13, 2012); and 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 Company's Quarterly Report on Form 10-Q filed on November 8, 2012)
10.2	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 Company's Quarterly Report on Form 10-Q filed on May 10, 2012)
10.3	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 Company's Registration Statement on Form S-1/A filed on July 25, 2011)
10.4	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 Company's Registration Statement on Form S-1/A filed on July 25, 2011)

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Exhibit Number	Description
10.5*	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 Company's Quarterly Report on Form 10-Q filed on August 13, 2012)
10.6*	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 Company's Quarterly Report on Form 10-Q filed on August 13, 2012)
10.7*	Amended and Restated Employment Agreement between Michael R. Starzer and Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed on August 26, 2011)
10.8*	Amended and Restated Employment Agreement between Gary A. Grove and Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed on August 26, 2011)
10.9*	Amended and Restated Employment Agreement between Patrick A. Graham and Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed on August 26, 2011)
10.10*	Employment Agreement between James R. Casperson and Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed on November 25, 2011)
10.11*	Bonanza Creek Energy, Inc. 2011 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed on November 4, 2011)
10.12	Stock Purchase Agreement, dated as of December 23, 2010, among Bonanza Creek Energy, Inc., Bonanza Creek Energy Operating Company, LLC, Project Black Bear LP and Her Majesty Queen in Right of Alberta (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed on July 25, 2011)
10.13	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 Company's Registration Statement on Form S-1/A filed on July 25, 2011)
10.14	Contribution Agreement, dated as of December 23, 2010, between Bonanza Creek Energy, Inc. and Bonanza Creek Energy Company, LLC (incorporated by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1/A filed on July 25, 2011)
10.15	Separation Agreement, dated as of November 1, 2012, between Bonanza Creek Energy, Inc. and James R. Casperson
10.16	Consulting Agreement, dated as of November 2, 2012, between Bonanza Creek Energy, Inc. and James R. Casperson,
21.1	List of subsidiaries
23.1	Consent of Hein & Associates LLP
23.2	Consent of Independent Petroleum Engineers, Cawley, Gillespie & Associates, Inc.
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)

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Exhibit Number	Description
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
99.1	Report of Independent Petroleum Engineers, Cawley, Gillespie & Associates, Inc. for reserves as of January 1, 2013
99.2	Report of Independent Petroleum Engineers, Cawley, Gillespie & Associates, Inc. for reserves as of January 1, 2012 (incorporated by reference to Exhibit 99.2 to the Company's Annual Report on Form 10-K filed on March 22, 2012)
99.3	Report of Independent Petroleum Engineers, Cawley, Gillespie & Associates, Inc. for reserves as of January 1, 2011 (incorporated by reference to Exhibit 99.1 to the Company's Registration Statement on Form S-1/A filed on July 25, 2011)
101	The following materials from the Bonanza Creek Energy, Inc. Annual Report on Form 10-K for the year ended December 31, 2012, formatted in XBRL (Extensible Business Reporting Language) include (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Stockholders' Equity, (iv) the Condensed Consolidated Statements of Cash Flows and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text. The information in Exhibit 101 is "furnished" and not "filed", as provided in Rule 402 of Regulation S-T

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Management Contract or Compensatory Plan or Arrangement

Filed or furnished herewith