Bonanza Creek Energy, Inc.
Form 10-K
February 29, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

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Form 10-K

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

For the fiscal year ended December 31, 2015
OR

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| .. | 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)

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

(720) 440-6100
(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

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

Securities Registered Pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting

company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x
The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates on June 30, 2015, based upon the closing price of $18.25 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $901,272,418. Excludes approximately 365,800 shares of the registrant's common stock held by executive officers, directors and stockholders that the registrant has concluded, solely for the purpose of the foregoing calculation, were affiliates of the registrant.
Number of shares of registrant's common stock outstanding as of February 22, 2016: 49,741,134
Documents Incorporated By Reference:
Portions of the registrant's definitive proxy statement for its 2016 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, are incorporated by reference into Part III of this report for the year ended December 31, 2015.

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BONANZA CREEK ENERGY, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2015

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Information Regarding Forward-Looking Statements

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

- the Company's business strategies and intent to maximize liquidity;
- reserves estimates;
- estimated sales volumes for 2016;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- ability to modify future capital expenditures;
- ability to consummate certain strategic divestitures;
- the Wattenberg Field being a premier oil and resource play in the United States;
- realization of anticipated cost reductions;
- compliance with debt covenants;
- ability to fund and satisfy obligations related to ongoing operations;
- compliance with government regulations;
- adequacy of gathering systems and continuous improvement of such gathering systems;
- impact from the lack of available gathering systems and processing facilities in certain areas;
- natural gas, oil and natural gas liquid prices and factors affecting the volatility of such prices;
- impact of lower commodity prices;
- sufficiency of impairments for the remainder of 2016;
- the ability to use derivative instruments to manage commodity price risk and ability to use such instruments in the future;
- our drilling inventory and drilling intentions;
- our estimated revenues and losses;
- the timing and success of specific projects;
- our implementation of long reach laterals in the Wattenberg Field;
- our use of multi-well pads to develop the Niobrara and Codell formations;
- intention to continue to optimize enhanced completion techniques and well design changes;
- intentions with respect to working interest percentages;
- management and technical team;
- outcomes and effects of litigation, claims and disputes;
- primary sources of future production growth;
- full delineation of the Niobrara B and C benches in our legacy acreage;
- our ability to replace oil and natural gas reserves;
- our ability to convert PUDs to producing properties within five years of their initial proved booking;

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- impact of recently issued accounting pronouncements;
- impact of the loss a single customer or any purchaser of our products;
- timing and ability to meet certain volume commitments related to purchase and transportation agreements;
- the impact of customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes and other industry-related constraints;
- our financial position;
- our cash flow and liquidity;
- the adequacy of our insurance; and
- other statements concerning our operations, economic performance and financial condition.

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

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

- the risk factors discussed in Part I, Item 1A of this Annual Report on Form 10-K;
- further declines or volatility in the prices we receive for our oil, natural gas liquids and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- ability of our customers to meet their obligations to us;
- our access to capital;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves and, in particular, probable and possible resources;
- the possibility that the industry may be subject to future local, state, and federal regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- seasonal weather conditions;
- lease stipulations;
- drilling and operating risks, including the risks associated with the employment of horizontal drilling techniques;
- our ability to acquire adequate supplies of water for drilling and completion operations;
- availability of oilfield equipment, services and personnel;
- exploration and development risks;
- competition in the oil and natural gas industry;
- management’s ability to execute our plans to meet our goals;
- risks related to our derivative instruments;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;

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- access to adequate gathering systems and pipeline take-away capacity to provide adequate infrastructure for the products of our drilling program;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- costs and other risks associated with perfecting title for mineral rights in some of our properties;
- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations or pricing.

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

## GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

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

"Asset Sale" shall mean any direct or indirect sale, lease (including by means of production payments and reserve sales and a sale and lease-back transaction), transfer, issuance or other disposition, or a series of related sales, leases, transfers, issuances or dispositions that are part of a common plan, of (a) shares of capital stock of a subsidiary (b) all or substantially all of the assets of any division or line of business of the Company or any subsidiary or (c) any other assets of the Company or any subsidiary outside of the ordinary course of business.

"Bbl" One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"Bcf" One billion cubic feet of natural gas.

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

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

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

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“Completion” The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
“Condensate” A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
“Developed acreage” The number of acres that are allocated or assignable to productive wells or wells capable of production.
“Development costs” Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves; (ii) drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly; (iii) acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.
“Development well” A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.
“Differential” The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead priced received.
“Deterministic method” The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.
“Dry hole” Exploratory or development well that does not produce oil or gas in commercial quantities.
“Economically producible” The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.
“Environmental assessment” A study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.
“ERISA” Employee Retirement Income Security Act of 1974.
“Estimated ultimate recovery (EUR)” Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.
“Exploratory well” A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.
“Extension well” A well drilled to extend the limits of a known reservoir.
“Field” An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.
“Finding and development costs” Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves, during the same period.

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"Formation" A layer of rock which has distinct characteristics that differ from nearby rock.
"GAAP" Generally accepted accounting principles in the United States.
"HH" Henry Hub index.
"Horizontal drilling" A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.
''Hydraulic fracturing" The process of injecting water, proppant and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.
"LIBOR" London interbank offered rate.
"MBbl" One thousand barrels of oil or other liquid hydrocarbons.
"MBoe" One thousand Boe.
"Mcf" One thousand cubic feet.
"MMBoe" One million Boe.
"MMBtu" One million British Thermal Units.
"MMcf" One million cubic feet.
"Net acres" The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.
"Net production" Production that is owned by the registrant and produced to its interest, less royalties and production due others.
"Net revenue interest" Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.
"Net well" Deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells expressed as whole numbers and fractions of whole numbers.
"NGL" Natural gas liquid.
"NYMEX" The New York Mercantile Exchange.
"Oil and gas producing activities" defined as (i) the search for crude oil, including condensate and natural gas liquids, or natural gas in their natural states and original locations; (ii) the acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties; (iii) the construction, drilling and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as lifting the oil and gas to the surface and gathering, treating and field processing (as in the case of processing gas to extract liquid hydrocarbons); and (iv) extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coal beds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.
"PDNP" Proved developed non-producing reserves.
"PDP" Proved developed producing reserves.
"Percentage-of-proceeds" A processing contract where the processor receives a percentage of the sold outlet stream, dry gas, NGLs or a combination, from the mineral owner in exchange for providing the processing services. In the Mid-Continent region, we are both a producer and, through ownership of gas plants, a processor, our sales volumes include volumes

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processed through the gas plants directly related to our working interest and volumes for which we are contractually entitled pursuant to the processing of gas from third party interests.
“Play” A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.
“Plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.
“Pooling” Pooling, either contractually or statutorily through regulatory actions, allows an operator to combine multiple leased tracts to create a governmental spacing unit for one or more productive formations. (Pooling is also known as unitization or communitization.). Ownership interests are calculated within the pooling/spacing unit according to the net acreage contributed by each tract within the pooling/spacing unit.
“Possible reserves” Those additional reserves that are less certain to be recovered than probable reserves.
“Probable reserves” Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
“Production costs” Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are (a) costs of labor to operate the wells and related equipment and facilities; (b) repairs and maintenance; (c) materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities; (d) property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and (e) severance taxes. Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the costs of oil and gas produced along with production (lifting) costs identified above.
“Productive well” An exploratory, development or extension well that is not a dry well.
“Proppant” Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.
“Proved developed reserves” Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
“Proved reserves” Those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

(i) The area of the reservoir considered as proved includes:

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

(b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher potions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

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

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

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

“Proved undeveloped reserves” or “PUD” Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled 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. Please refer to the footnote 2 of the Proved Reserves table in Item 1 of this Annual Report on Form 10-K for additional discussion.

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

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

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

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"Reserve replacement percentage" The sum of sales of reserves, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.
"Reservoir" A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
"Resource play" Refers to drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.
"Royalty interest" An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas or NGLs produced and sold unencumbered by expenses of drilling, completing and operating of the affected well.
"Sales volumes" All volumes for which a reporting entity is entitled to proceeds, including production, net to the reporting entity's interest and third party production obtained from percentage-of-proceeds contracts and sold by the reporting entity.
"Service well" A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.
"Spacing" Spacing as it relates to a spacing unit is defined by the governing authority having jurisdiction to designate the size in acreage of a productive reservoir along with the appropriate well density for the designated spacing unit size. Typical spacing for conventional wells is 40 acres for oil wells and 640 acres for gas wells.
"Three stream" The separate reporting of NGLs extracted from the natural gas stream and sold as a separate product.
"Undeveloped acreage" Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.
"Undeveloped reserves" Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped oil and gas reserves."
"Working interest" The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.
"Workover" Operations on a producing well to restore or increase production.
"WTI" West Texas Intermediate index.

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PART I

Item 1. Business.

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

Overview

Bonanza Creek is an independent energy company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas in the United States. Bonanza Creek Energy, Inc. was incorporated in Delaware on December 2, 2010 and went public in December 2011.

Our oil and liquids-weighted assets are concentrated primarily in the Wattenberg Field in Colorado and the Dorcheat Macedonia Field in southern Arkansas. In addition, we own and operate oil-producing assets in the North Park Basin in Colorado and the McKamie Patton Field in southern Arkansas. The Wattenberg Field is one of the premier oil and gas resource plays in the United States benefiting from a low cost structure, strong production efficiencies, established reserves and prospective drilling opportunities, which allows for predictable production and reserve growth.

Our Business Strategies

Beginning in 2014, the oil and natural gas industry began to experience a sharp decline in commodity prices. Caused in part by global supply and demand imbalances and an oversupply of natural gas in the United States, the pricing declines have extended into 2016 and the timing of any rebound is uncertain. Low commodity prices resulted in impairments and a reduction of our revenues, profitability, cash flows, proved reserve values and stock price. If the industry downturn continues for an extended period or becomes more severe, we could experience additional impairments and further material reductions in revenues, profitability, cash flows, proved reserves and stock price.

Given the current depressed commodity price environment, our primary goals are to preserve stockholder value by maximizing the cash flows from our existing production, optimize the Company's liquidity position and position our organization and leasehold for increased development activity when the appropriate commodity price signals are observed. We intend to accomplish this by focusing on the following key strategies:

- 2016 Liquidity. We are considering various strategies to reinforce our balance sheet and improve our liquidity. These strategies include potential asset sales and joint ventures or other arrangements that would enable us to support development of our core areas with additional third-party capital, debt restructurings, the issuance of new debt or equity and conservation of our liquid assets. The outcome of these potential alternatives, the timing of which cannot be accurately predicted at this time, are likely to affect our liquidity, future operations and financial condition.
- 2016 Capital Expenditures. We expect to control our reduced liquidity during 2016 by scaling back our capital expenditures to match the current commodity pricing environment. Although we cannot predict or control future commodity prices, our expected 2016 capital expenditure budget has been decreased to accommodate the reduction in commodity prices. We have a modest capital program of $40.0 million to $50.0 million planned for 2016 in order to conserve our liquid assets. These costs will largely be incurred during the first quarter of 2016.
- Cost-Reduction Initiatives. We have taken steps to reduce our future capital, operating and corporate costs. During 2015, we negotiated with our primary suppliers and service providers resulting in an approximate 29% reduction in our drilling and completion costs on our standard reach lateral wells and an approximate 12% reduction in our lease operating expense per Boe. We also took measures to reduce corporate costs by reducing headcount resulting in a $5.3 million reduction in general and administrative expense on an annual basis and we continue to focus on cost reduction opportunities.

Competitive Strengths

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Control the timing of resource development on our leasehold. We maintain a 90% working interest and operate the majority of our future development drilling inventory. This allows the Company to control the pace and magnitude of

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our future capital expenditures and provides us the ability to wait for increased commodity prices prior to undertaking future projects.

- Continue to align our operations and cost structure to current economic conditions. We operate 98% of our current production. All decisions related to the technical operation of these producing properties and the costs associated with operation of these assets are made by the Company. We leverage our operating and asset management skills to optimize the productivity of these properties while minimizing the ongoing costs of operations.

- Large, contiguous leasehold in the Denver-Julesburg Basin. We control approximately 69,000 net acres in the Wattenberg Field in Weld County. We believe the contiguous nature of our leasehold allows for the most efficient resource development by providing the greatest ability to drill large pads of horizontal wells with centralized surface facilities servicing multiple pads over the life of field development.

- High degree of geologic and technical control. We have successfully delineated the majority of our leasehold over the past four years. When coupled with offsetting operator results, we believe our future development locations have a high degree of definition.

- Liquids-weighted reserves. While current commodity prices have caused us to significantly reduce our anticipated drilling plan for 2016, we believe the commodity mix of our reserves provides significant leverage to any future recovery in oil prices.

- Significant inventory of undrilled locations available for development. As of December 31, 2015, we had 204 gross (163.9 net) proved undeveloped locations (220 gross standard reach lateral equivalents) identified in the Wattenberg Field, which represents a 3.4 year future development inventory assuming a continuous one rig drilling program.

In 2015, we successfully drilled 101 and completed 110 productive operated wells and participated in drilling seven and completing six productive non-operated wells. The resulting production rates achieved by this program increased sales volumes by 20% over the previous year to 28,272 Boe/d of which 76% was crude oil and natural gas liquids ("NGLs"). We had nine operated wells and three non-operated wells in progress as of December 31, 2015. Our sales volumes during the fourth quarter of 2015 were 28,572 Boe/d, a 10% increase over the comparable period in 2014. The following tables summarize our estimated proved reserves, PV-10 reserve value, sales volumes, and projected capital spend as of December 31, 2015:

| Estimated Proved Reserves | Crude Oil (MBbls) | Natural Gas (MMcf) | Natural Gas Liquids (MBbls) | Total Proved (MBoe) |
|---|---|---|---|---|
| Developed | | | | |
| Rocky Mountain | 21,074 | 53,864 | 8,704 | 38,756 |
| Mid-Continent | 7,818 | 23,616 | 1,655 | 13,409 |
| | 28,892 | 77,480 | 10,359 | 52,165 |
| Undeveloped | | | | |
| Rocky Mountain | 24,689 | 49,916 | 8,400 | 41,408 |
| Mid-Continent | 3,812 | 16,831 | 1,159 | 7,776 |
| | 28,501 | 66,747 | 9,559 | 49,184 |
| Total Proved | 57,393 | 144,227 | 19,918 | 101,349 |

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| | Estimated Proved Reserves at December 31, 2015[1] | | | | Sales Volumes for the Year Ended December 31, 2015 | | Projected | Net Proved Undeveloped Drilling Locations |
|---|---|---|---|---|---|---|---|---|
| | Total Proved (MBoe) | % of Total | % Proved Developed | PV-10 ($ in MM)[2] | Average Net Daily Sales Volumes (Boe/d) | % of Total | 2016 Capital Expenditures ($ in millions) | as of December 31, 2015 |
| Rocky Mountain | 80,164 | 79 % | 48 % | $ 247.8 | 22,987 | 81 % | $ 36.5-46.5 | 163.9 |
| Mid-Continent[3] | 21,185 | 21 % | 63 % | 80.0 | 5,285 | 19 % | 3.5 | 81.1 |
| Total | 101,349 | 100 % | 51 % | $ 327.8 | 28,272 | 100 % | $ 40.0-50.0 | 245.0 |

(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 $50.28 per Bbl WTI and $2.59 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $6.28 per Bbl of crude oil and a decrease of $0.26 per MMBtu of natural gas.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil, natural gas, and natural gas liquid reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices, after adjustment for differentials in location and quality, for each of the preceding twelve months. We believe that PV-10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV-10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts and sophisticated investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating the Company and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. Please refer to the Reconciliation of PV-10 to Standardized Measure presented several pages below.

(3) Mid-Continent sales volumes were 5,285 Boe/d for 2015, which is comprised of 4,684 Boe/d of production net to our interest and 601 Boe/d sales volumes from our percentage-of-proceeds contracts.

Our Operations

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

Rocky Mountain Region

The two main areas in which we operate in the Rocky Mountain region are the Wattenberg Field in Weld County, Colorado and the North Park Basin in Jackson County, Colorado. As of December 31, 2015, our estimated proved reserves in the Rocky Mountain region were 80,164 MBoe, which represented 79% of our total estimated proved reserves and contributed 22,987 Boe/d, or 81%, of sales volumes during 2015.

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, 2015, our Wattenberg position consisted of approximately 91,000 gross (69,000 net) acres. We own 3-D seismic surveys covering the majority of our acreage in the Wattenberg Field, which helps provide efficient and targeted horizontal drilling operations. We have seen an uplift in production from larger stimulations using approximately 1,500 pounds per foot and from our new mono-bore well design that incorporates the plug-and-perf completion technique. We plan to incorporate both techniques on wells drilled and completed during 2016.

The Wattenberg Field is now primarily developed for the Niobrara and Codell formations using horizontal drilling and multi-stage fracture stimulation techniques. We believe the Niobrara B and C benches have been fully delineated on our legacy acreage, while the Codell formation continues to be delineated in our eastern legacy acreage. Our delineation wells in our Northern acreage have validated the productivity of the Niobrara Chalk.

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Our estimated proved reserves at December 31, 2015 in the Wattenberg Field were 79,869 MBoe. As of December 31, 2015, we had a total of 620 gross producing wells, of which 401 were horizontal wells, and our sales volumes during 2015 were 22,894 Boe/d. Our sales volumes for the fourth quarter of 2015 were 23,535 Boe/d. As of December 31, 2015, our working interest for all producing wells averaged approximately 90% and our net revenue interest was approximately 74%.

Our strategy in 2015 was to utilize existing infrastructure and maximize extended reach lateral wells to allow us to reduce costs. We also established a midstream entity, Rocky Mountain Infrastructure, LLC, to house our gas gathering and midstream facility assets that we subsequently deemed as held for sale during the same year. We continued to expand our proved reserves in this area by drilling non-proved horizontal locations. As of December 31, 2015, we have an identified drilling inventory of approximately 204 gross (163.9 net) proved undeveloped ("PUD") drilling locations (220 gross standard reach lateral equivalents) on our acreage with an average standard reach lateral well cost of $3.0 million, based on average capital expenditures in 2015 when excluding outliers. During 2015, we drilled 84 and completed 95 gross horizontal wells.

The first criteria of our 2015 operated drilling program was to drill near our central production facilities. We maximized our extended reach lateral development in the program and were successful in achieving 48% of our program as extended reach laterals on a standard reach lateral equivalent basis (47 of 98 standard reach lateral equivalents). During the year, in the Niobrara benches, we drilled 26 extended reach lateral wells and 45 standard reach lateral wells. We completed 28 extended reach lateral wells and 51 standard reach lateral wells. In addition, we drilled 6 Codell standard reach lateral wells and completed 10 with carryover from 2014. We also participated in the drilling of 2 standard reach lateral wells (0.8 net) and 5 extended reach lateral wells (1.0 net) and the completion of 6 extended reach lateral wells (0.8 net) in the Niobrara formation. During 2015 we analyzed our test results using various completion fluids and additives, frac sand concentration and casing designs and configurations.

We estimate our capital expenditures in the Wattenberg Field for the first quarter 2016 will range from $35.0 million to $45.0 million, to be used to drill two extended reach lateral wells in the Niobrara formation, six standard reach lateral wells in the Niobrara and one standard reach lateral well in the Codell. We anticipate completing four medium reach lateral wells and eight standard reach lateral wells in the Niobrara in the first quarter of 2016 and participate in three non-operated well completions (two standard reach laterals and one extended reach lateral). The Company expects well costs to continue to contract in the near term, targeting a range of $2.5 million to $2.7 million for a standard reach lateral well down from $4.2 million and is targeting approximately $4.3 million for an extended reach lateral well down from $5.1 million. Further budget guidance for the remainder of 2016 will be determined based upon the final outcome of our divestiture processes. Please refer to Note 3 - Assets Held for Sale in Part II, Item 8 of this Annual Report on Form 10-K, for additional discussion. In 2016, we plan to use the monobore well design that incorporates the plug-and-perf completion technique and 1,500 pounds of frac sand per lateral foot.

North Park Basin - Jackson County, Colorado. We control approximately 19,000 gross (15,000 net) acres in the North Park Basin in Jackson County, Colorado, all prospective for the Niobrara oil shale. We operate the North and South McCallum Fields, which currently produce light oil, which is trucked to market. We currently have all of our assets within the North Park Basin held for sale.

In the North Park Basin, our estimated proved reserves as of December 31, 2015 were approximately 295 MBoe, 100% of which was crude oil, and our sales volumes during 2015 were 93.4 Boe/d. Our sales volumes for the fourth quarter of 2015 were 70.6 Boe/d. During 2014, we drilled and cored one vertical well, which was subsequently evaluated in 2015 and deemed a dry hole at such time. There were no wells drilled during 2015 in the North Park Basin.

None of our 2016 capital budget is assigned to the North Park Basin.

Mid-Continent Region

In southern Arkansas, we target the oil-rich Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton Fields. As of December 31, 2015, our estimated proved reserves in the Mid-Continent region were 21,185 MBoe, 68% of which were oil and NGLs and 63% of which were proved developed. We currently have 294 gross producing vertical wells. During 2015, we drilled 24 wells and successfully completed 21 operated wells in the Mid-Continent region. We achieved a sales volume rate for 2015 of 5,285 Boe/d, of which 69% was from oil and NGLs, and a sales volume rate for the fourth quarter of 2015 of 4,966 Boe/d. Productive reservoirs range in depth from 4,500 to 9,000 feet. Those reservoirs include the Smackover and the Pettet, but our primary development target is the Cotton Valley sands. We estimate our capital expenditures in the Mid-Continent region for 2016 could be $3.5 million with the continuation of the recompletion program, although we currently have all of our assets within the Mid-Continent region held for sale.

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Dorcheat Macedonia.  In the Dorcheat Macedonia Field, we average an approximate 89% working interest and an approximate 73% net revenue interest on all producing wells, and the majority of our acreage is held by unitization, production, or drilling operations. We have approximately 260 gross producing wells and our production during 2015 was approximately 4,450 Boe/d (5,051 Boe/d sales volumes). During the fourth quarter of 2015, our production was 4,129 Boe/d (4,730 Boe/d sales volumes). Our proved reserves in this field are approximately 20,073 MBoe. As of December 31, 2015, we have identified approximately 96 gross (81.1 net) PUD drilling locations on our acreage in this area. During 2015, we drilled 22 and successfully completed 21 vertical Cotton Valley wells in the Dorcheat Macedonia Field.

Other Mid-Continent.  We own additional interests in the McKamie Patton Field in the Mid-Continent region near the Dorcheat Macedonia Field. As of December 31, 2015, our estimated proved reserves were approximately 1,112 MBoe, and sales volume during 2015 were approximately 234 Boe/d. During the fourth quarter of 2015, our production was 236 Boe/d.

Gas Processing Facilities.  Our Mid-Continent gas processing facilities are located in Lafayette and Columbia counties in Arkansas and are strategically located to serve our production in the region. In the aggregate, our Arkansas gas processing facilities have approximately 40 MMcf/d of capacity with 86,000 gallons per day of associated NGL capacity. As a cost savings measure, during 2015 we idled our McKamie Patton gas plant dropping our current capacity in the Dorcheat Macedonia Field to 24 MMcf/d with 54,000 gallons per day of associated NGL capacity. Our ownership of these facilities and related gathering pipeline provides us with the benefit of controlling processing and compression of our natural gas production and the timing of connection to our newly completed wells.

Reserves

Estimated Proved Reserves

The summary data with respect to our estimated proved reserves presented below has been prepared in accordance with rules and regulations of the Securities and Exchange Commission (the “SEC”) applicable to companies involved in oil and natural gas producing activities. Our reserve estimates do not include probable or possible reserves, categories which SEC rules do permit us to disclose in public reports. Our estimated proved reserves for the years ended December 31, 2015, 2014 and 2013 were determined using the preceding twelve months’ unweighted arithmetic average of the first-day-of-the-month prices. For a definition of proved reserves under the SEC rules, please see the Glossary of Oil and Natural Gas Terms included in the beginning of this report.

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

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The table below summarizes our estimated proved reserves at December 31, 2015, 2014 and 2013 for each of the regions and currently producing fields in which we operate. The proved reserve estimates at December 31, 2015 and 2014 are based on reports prepared by our internal corporate reservoir engineering group, of which 100% were audited by Netherland, Sewell & Associates, Inc. ("NSAI"), our third-party independent reserve engineers. The proved reserve estimates at December 31, 2013 are based on reports prepared by NSAI. In preparing these reports for 2013, NSAI evaluated 100% of our estimated proved reserves. For more information regarding our independent reserve engineers, please see Independent Reserve Engineers below. The information in the following table is not intended to represent the current market value of our proved reserves nor does it give any effect to or reflect our commodity derivatives or current commodity prices.

| Region/Field | At December 31, 2015 | 2014 | 2013 |
|---|---|---|---|
| | (MMBoe) | | |
| Rocky Mountain | 80.1 | 68.1 | 49.1 |
| Wattenberg | 79.8 | 67.8 | 48.8 |
| North Park | 0.3 | 0.3 | 0.3 |
| Mid-Continent | 21.2 | 21.4 | 20.7 |
| Dorcheat Macedonia | 20.1 | 19.9 | 19.4 |
| McKamie Patton | 1.1 | 1.5 | 1.3 |
| Total | 101.3 | 89.5 | 69.8 |

The following table sets forth more information regarding our estimated proved reserves at December 31, 2015, 2014 and 2013:

| | At December 31, 2015 | | 2014 | | 2013 | |
|---|---|---|---|---|---|---|
| Reserve Data(1): | | | | | | |
| Estimated proved reserves: | | | | | | |
| Oil (MMBbls) | 57.4 | | 54.7 | | 43.6 | |
| Natural gas (Bcf) | 144.2 | | 188.6 | | 139.6 | |
| Natural gas liquids (MMBbls) | 19.9 | | 3.4 | | 2.9 | |
| Total estimated proved reserves (MMBoe)(2) | 101.3 | | 89.5 | | 69.8 | |
| Percent oil and liquids | 76 | % | 65 | % | 67 | % |
| Estimated proved developed reserves: | | | | | | |
| Oil (MMBbls) | 28.9 | | 28.3 | | 20.7 | |
| Natural gas (Bcf) | 77.5 | | 94.5 | | 59.2 | |
| Natural gas liquids (MMBbls) | 10.4 | | 2.2 | | 1.6 | |
| Total estimated proved developed reserves (MMBoe)(2) | 52.2 | | 46.3 | | 32.2 | |
| Percent oil and liquids | 75 | % | 66 | % | 69 | % |
| Estimated proved undeveloped reserves: | | | | | | |
| Oil (MMBbls) | 28.5 | | 26.4 | | 22.9 | |
| Natural gas (Bcf) | 66.7 | | 94.1 | | 80.4 | |
| Natural gas liquids (MMBbls) | 9.6 | | 1.2 | | 1.3 | |
| Total estimated proved undeveloped reserves (MMBoe)(2) | 49.2 | | 43.2 | | 37.6 | |
| Percent oil and liquids | 77 | % | 64 | % | 64 | % |

(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 $50.28 per Bbl WTI and $2.59 per MMBtu HH, $94.99 per Bbl WTI and $4.35 per MMBtu HH, and $96.91 per Bbl WTI and $3.67 per MMBtu HH for the years ended December 31, 2015, 2014 and 2013, respectively. Adjustments were made for location and grade.

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

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Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic productivity at greater distances.

Proved undeveloped locations in our December 31, 2015 reserve report are included in our development plan and are scheduled to be drilled within five years from their initial proved booking date. The Company’s management evaluated the proved undeveloped drilling plan using the Company’s current budget price deck and the liquidation model for general and administrative costs, estimated interest payments and hedging payments. The budget price deck was derived from various external sources, such as the NYMEX strip price, the S&P and Moody's indices, prices from equity analysts who cover the Company, along with internal management estimates. We have a strong PUD conversion rate as evidenced by our 2014 conversion rate of 21% and our 2015 conversion rate of 16%. Given the anticipated limited drilling program in 2016, we analyzed the potential PUD loss within the Wattenberg Field at the end of 2016 to be less than 1%. The reliable technologies used to establish our proved reserves are a combination of pressure performance, geologic mapping, offset productivity, electric logs, and production data.

Estimated proved reserves at December 31, 2015 were 101.3 MMBoe, a 13% increase from estimated proved reserves of 89.5 MMBoe at December 31, 2014. Approximately 79% of our December 31, 2015 proved reserves are attributed to the Rocky Mountain region, over 99% of which are attributed to the Wattenberg Field. The net increase in our reserves of 11.8 MMBoe is the result of additions in extensions and discoveries of 12.0 MMBoe, coupled with a net positive revision of 8.4 MMBoe (engineering and pricing) and net acquisitions of 1.5 MMBoe offset by 10.1 MMBoe in production. The Mid-Continent region contributed the acquisition reserves of 1.5 MMBoe, 2.5% the extensions and discoveries and less than 4% of the reserve revisions.

The addition in extension and discoveries is primarily the result of drilling and completing 63 unproved horizontal locations (including five non-operated) in the Niobrara and the Codell formations in the Wattenberg Field during 2015 and the addition of 17 new horizontal proved undeveloped locations. Twenty-eight additional proved undeveloped locations were added in the engineering revision category since the offsetting proved developed producing wells were drilled prior to 2015. For the year ended December 31, 2015, greater than 90% of our horizontal development in the Wattenberg Field was in the Niobrara formation, the majority of which was on 80-acre spacing within each bench. All Niobrara proved undeveloped locations are spaced on 80 acres.

Total Company positive engineering revisions as of December 31, 2015, were 37,174 Mboe, of which 30,086 Mboe (81%) related to reserve changes in the Wattenberg Field. This positive engineering revision is offset by a negative pricing revision of 21,417 Mboe in the Wattenberg Field. The majority of the positive revisions in the Wattenberg Field resulted from a combination of decreased drilling and completion costs, $3.0 million per standard reach lateral well as of December 31, 2015 compared to $4.2 million at December 31, 2014, a 29% decrease, and an increase in productivity from horizontal proved developed producing wells which increased the offsetting proved undeveloped reserves. The increase in proved developed producing reserves is primarily attributed to the installation of infrastructure in the east side of our Wattenberg Field acreage which removed the producing constraint that inhibited productivity over the last two years of development in that area. Another significant contribution to the positive reserve revision in the Wattenberg Field results from a contract change as of January 1, 2015 which gives our Company ownership of the natural gas liquids from our gas production. This conversion from two stream (wet gas and oil) to three stream (dry gas, natural gas liquids and oil) added 8,560 Mboe to our proved reserves as of December 31, 2015. With the addition of 45 horizontal proved undeveloped locations in the Wattenberg Field to the proved reserves at December 31, 2015, the total proved undeveloped location count is 204 (220 standard reach lateral equivalents) and was 226 as of December 31, 2014. Our five-year plans include the drilling of these proved undeveloped locations before they expire. The 2016 drilling program included in the year end 2015 reserves is a one rig program estimated to convert 16% of our year end 2015 proved undeveloped reserves in the Wattenberg Field. If commodity prices do not increase significantly or if our properties held for sale are not sold, we will cease drilling at the end of the first quarter 2016. At that time, we anticipate we will have drilled 20% of the proved undeveloped locations scheduled to be drilled in 2016. There is only one horizontal proved undeveloped location in the Wattenberg Field at risk to expire in 2016 if we do not continue drilling past the first quarter of the year. If we cease drilling at the end of the first quarter of 2016, run a single rig program in 2017 and add one additional rig per year thereafter for the remaining three years, all remaining proved undeveloped locations will be developed within their five year windows. A negative pricing revision of 28,810 Mboe for the Company resulted from a decrease in average commodity price from $94.99 per Bbl WTI and $4.35 per MMBTU HH for the year ended December 31, 2014 to $50.28 per Bbl WTI and $2.59 per MMBTU HH for the year ended December 31, 2015.

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Estimated proved reserves at December 31, 2014 were 89.5 MMBoe, a 28% increase from estimated proved reserves of 69.8 MMBoe at December 31, 2013. The net increase in reserves of 19.7 MMBoe was the result of additions in extensions and discoveries of 20.2 MMBoe, primarily due to the development of the Niobrara B and C benches and the Codell formations in the Wattenberg Field, coupled with a net positive revision of 7.1 MMBoe (engineering and pricing) and net acquisitions (acquisitions less divestitures) of 0.8 MMBoe offset by 8.4 MMBoe in production. The addition in extension and discoveries was primarily the result of drilling and completing 99 unproved horizontal locations (including 12 non-operated) in the Niobrara and the Codell formations in the Wattenberg Field during 2014 and the addition of 37 new horizontal proved undeveloped locations directly offsetting new wells brought online in 2014. As of December 31, 2014, approximately 70% of our horizontal development in the Wattenberg Field was in the Niobrara B formation, the majority of which was on 80-acre spacing. The net positive engineering revision was primarily the result of adding new Niobrara B proved undeveloped locations on 80-acre spacing, directly offsetting economic proved producing Niobrara B wells drilled prior to 2014, diagonal offsets to economic Niobrara B proved producing wells and a relatively small number of locations greater than one offset to economic Niobrara B proved producing wells but within developed areas and surrounded by Niobrara B proved producing wells. A total of 119 horizontal proved undeveloped locations were added to the proved reserves at December 31, 2014 of which 86 (72%) were direct offsets to economic proved producing wells (drilled in 2014 or prior to 2014), 21 (18%) were direct offsets in a diagonal pattern to economic proved producing wells and 12 (10%) were greater than one offset from economic proved producing wells. The reasonable certainty of the reserves associated with the latter two categories of proved undeveloped locations was based on analysis of the immediate surrounding productivity of the Niobrara B bench and detailed geologic mapping. All Niobrara proved undeveloped locations were spaced on 80 acres. The positive engineering revision was offset by a small negative performance revision of approximately 540 MBoe. A negative pricing revision of 0.25 MMBoe resulted from a decrease in average commodity price from $96.91 per Bbl WTI and $3.67 per MMBTU HH for the year ended December 31, 2013 to $94.99 per Bbl WTI and $4.35 per MMBTU HH for the year ended December 31, 2014.

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

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

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The following table provides a reconciliation of PV-10 to Standardized Measure at December 31, 2015, 2014 and 2013:

| | December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (in millions) | | |
| PV-10 | $ 327.8 | $ 1,340.5 | $ 1,227.2 |
| Present value of future income taxes discounted at 10%[(1)] | — | (233.1) | (301.9) |
| Standardized Measure | $ 327.8 | $ 1,107.4 | $ 925.3 |

(1) The tax basis of our oil and gas properties as of December 31, 2015 provides more tax deduction than income generated from our oil and gas properties when the reserve estimates were prepared using $50.28 per Bbl WTI and $2.59 per MMBTU HH.

Proved Undeveloped Reserves

| | Net Reserves, MBoe | | |
|---|---|---|---|
| | At December 31, | | |
| | 2015 | 2014 | 2013 |
| Beginning of year | 43,246 | 37,603 | 29,192 |
| Converted to proved developed | (6,994) | (7,791) | (3,047) |
| Additions from capital program | 2,308 | 5,596 | 16,535 |
| Acquisitions | 1,541 | — | 1,779 |
| Revisions | 9,083 | 7,838 | (6,856) |
| End of year | 49,184 | 43,246 | 37,603 |

At December 31, 2015, our proved undeveloped reserves were 49,184 MBoe, all of which are scheduled to be drilled within five years of their initial proved booking date. During 2015, the Company converted 16% of its proved undeveloped reserves (52 gross wells representing net reserves of 6,994 MBoe) at a cost of $121.0 million. Executing our 2015 capital program resulted in the addition of 2,308 MBoe (17 gross wells) in proved undeveloped reserves in the Wattenberg Field. A small acquisition within the field limits of the Dorcheat Macedonia Field added 14 gross proved undeveloped locations and 1,541 MBoe to our reserves. The positive engineering revision of 9,083 MBoe was primarily the result of adding 28 gross new proved undeveloped locations in the Wattenberg Field on 80-acre spacing, the majority directly offsetting economic proved producing wells drilled prior to 2015, and an increase in east Wattenberg Field proved undeveloped reserves resulting from increased productivity due to the installation of infrastructure which eliminated a production constraint thereby allowing productivity to rise, proved developed reserves to increase, and associated proved undeveloped reserves to increase by an estimated 3.0 MMBoe.

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

At December 31, 2013, our proved undeveloped reserves were 37,603 MBoe, all of which were scheduled to be drilled within five years of their initial proved booking date. During 2013, 3,047 MBoe or 10% of our proved undeveloped reserves (40 gross wells) were converted into proved developed reserves requiring $62.8 million of drilling and completion capital. Continued delineation and testing in our Wattenberg Field in 2013 resulted in a conversion rate less than 20% for the

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year. Execution of our 2013 capital program resulted in the addition of 16,535 MBoe in proved undeveloped reserves (92 gross wells). The negative revision of 6,856 MBoe resulted from a combination of eliminating vertical proved undeveloped locations in the Wattenberg Field continuing the transition to horizontal development and a reduction in proved undeveloped reserves in the Dorcheat Macedonia Field based on proved developed performance.

Internal controls over reserves estimation process

Our policies regarding internal controls over the recording of reserves estimates require reserves to be in compliance with SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The Company's Reserves Committee reviews significant reserve changes on an annual basis and our third-party independent reserve engineers, NSAI, is engaged by and has direct access to the Reserves Committee. NSAI audited 100% of our estimated proved reserves at December 31, 2015 and 2014, and evaluated 100% of our estimated proved reserves in the preparation of our reserve report at December 31, 2013.

Responsibility for compliance in reserves estimation is delegated to our internal corporate reservoir engineering group managed by Lynn E. Boone. Ms. Boone is our Senior Vice President, Planning & Reserves. Ms. Boone attended the Colorado School of Mines and graduated in 1982 with a Bachelor of Science degree in Chemical and Petroleum Refining Engineering. She attended the University of Oklahoma and graduated in 1985 with a Master of Science degree in Petroleum Engineering. Ms. Boone has been involved in evaluations and the estimation of reserves and resources for over 32 years. She has managed the technical reserve process at a company level for over ten years. Collectively with Ms. Boone, our internal corporate reservoir engineering group has over 100 years of experience. Our technical team works with our banking syndicate members at least twice each year for a valuation of our reserves by the banks in our lending group and their engineers in determining the borrowing base under our revolving credit facility.

Independent Reserve Engineers

The reserves estimates for the years ended December 31, 2015 and 2014 shown herein have been independently audited by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, and prepared by them for the year ended December 31, 2013. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates set forth in the NSAI audit letter incorporated herein are Mr. Dan Smith and Mr. John Hattner. Mr. Smith, a Licensed Professional Engineer in the State of Texas (No. 49093), has been practicing consulting petroleum engineering at NSAI since 1980 and has over seven years of prior industry experience. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 559), has been practicing consulting petroleum geoscience at NSAI since 1991, and has over 11 years of prior industry experience. He graduated from University of Miami, Florida, in 1976 with a Bachelor of Science Degree in Geology; from Florida State University in 1980 with a Master of Science Degree in Geological Oceanography; and from Saint Mary's College of California in 1989 with a Master of Business Administration Degree. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Production, Revenues and Price History

The recent collapse in oil prices is among the most severe on record. The daily NYMEX WTI oil spot price went from a high of $107.62 per Bbl in 2014 to low of $34.73 per Bbl in 2015. The drop in crude oil pricing is due in large part to increased production levels, crude oil inventories and recessed global economic growth. Oil prices are also impacted by real or perceived geopolitical risks in oil producing regions, the relative strength of the U.S. dollar, weather and the global economy. Gas prices have been under downward pressure during 2015 due to excess supply leading to higher levels of gas in storage when compared to the 5-year average. We expect that depressed oil prices will lead to cuts in the exploration and production budgets to reduce incremental oil supply, which should ultimately restore equilibrium to the world oil market and rebalance oil prices.

An extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets. We believe that we have the means necessary to fund our limited drilling program in 2016 with operating cash flows. Our drilling program consists of limited drilling in the first quarter of 2016 with no drilling for the remainder of the year until such time that oil prices rebound or we execute a divestiture. Please refer to Part II,

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Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion on liquidity.

Sensitivity Analysis

If oil and natural gas SEC prices declined by 10% then our PV-10 value as of December 31, 2015 would decrease by approximately 12% or $39.5 million. The PV-10 of our Rocky Mountain region, primarily our Wattenberg assets, would decrease by 9.5% or $23.5 MM.

We recorded $419.3 million and $321.2 million of proved property impairments in the Rocky Mountain and Mid-Continent regions, respectively, during the third and fourth quarters of 2015. We believe that we have sufficiently written-down our proved properties to their current fair value and do not anticipate triggering additional impairments in 2016 when analyzing price changes only. Impairment calculations use undiscounted cash flows to indicate whether assets are impaired. After our 2015 impairments, our asset carrying values are well below the undiscounted cash flows. We ran various impairment reserve runs keeping all assumptions constant except for pricing and concluded that the NYMEX WTI strip price would have to drop below $20.00 per Bbl for 2016, 2017 and 2018 to trigger an additional impairment, assuming prices revert back to budget pricing for years subsequent to 2018.

For the oil and natural gas derivatives outstanding at December 31, 2015, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2015 would change our derivative gain by $(0.3) million and $0.3 million, respectively.

Production

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

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| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014(1) | 2013(1) |
| Oil: | | | |
| Total Production (MBbls) | 6,072.3 | 5,618.7 | 3,887.2 |
| Wattenberg Field | 5,029.6 | 4,486.4 | 2,775.6 |
| Dorcheat Macedonia Field | 923.2 | 1,025.6 | 925.2 |
| Average sales price (per Bbl), including derivatives | $ 62.10 | $ 84.00 | $ 88.82 |
| Average sales price (per Bbl), excluding derivatives | $ 40.98 | $ 81.95 | $ 91.84 |
| Natural Gas: | | | |
| Total Production (MMcf) | 14,110.9 | 15,316.1 | 9,975.9 |
| Wattenberg Field | 11,020.8 | 11,372.7 | 6,269.1 |
| Dorcheat Macedonia Field | 3,090.5 | 4,030.6 | 3,598.3 |
| Average sales price (per Mcf), including derivatives | $ 2.01 | $ 5.16 | $ 4.70 |
| Average sales price (per Mcf), excluding derivatives | $ 1.82 | $ 5.11 | $ 4.66 |
| Natural Gas Liquids: | | | |
| Total Production (MBbls) | 1,675.9 | 260.6 | 352.8 |
| Wattenberg Field | 1,489.9 | 16.8 | 10.2 |
| Dorcheat Macedonia Field | 186.0 | 243.8 | 342.6 |
| Average sales price (per Bbl), including derivatives | $ 9.49 | $ 49.14 | $ 51.74 |
| Average sales price (per Bbl), excluding derivatives | $ 9.49 | $ 49.14 | $ 51.74 |
| Oil Equivalents: | | | |
| Total Production (MBoe) | 10,100.0 | 8,365.6 | 5,902.7 |
| Wattenberg Field | 8,356.3 | 6,398.6 | 3,830.7 |
| Dorcheat Macedonia Field | 1,624.2 | 1,874.7 | 1,867.5 |
| Average Daily Production (Boe/d) | 27,671.2 | 22,919.3 | 16,171.8 |
| Wattenberg Field | 22,894.1 | 17,530.5 | 10,495.0 |
| Dorcheat Macedonia Field | 4,450.0 | 5,136.3 | 5,116.4 |
| Average Production Costs (per Boe)(3)(2) | $ 7.56 | $ 8.66 | $ 8.09 |

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

(2) Excludes ad valorem and severance taxes.

(3) Represents lease operating expense per Boe using total production volumes of 10,100.0 MBoe and 8,365.6 MBoe for 2015 and 2014, respectively. Total production volumes exclude volumes from our percentage-of-proceeds contracts of 219.4 MBoe and 215.3 MBoe for 2015 and 2014, respectively.

Principal Customers

Four of our customers, Kaiser-Silo Energy Company, Lion Oil Trading & Transportation, Inc., Plains Marketing LP and Duke Energy Field Services comprised 31%, 16%, 11% and 11%, respectively, of our total revenue for the year ended December 31, 2015. No other single non-affiliated customer accounted for 10% or more of our oil and natural gas sales in 2015. We believe the loss of any one customer would not have a material effect on our financial position or results of operations because there are numerous potential customers for our production.

Delivery Commitments

We have entered into two purchase and transportation agreements to deliver a fixed determinable quantity of crude oil within the Wattenberg Field. The first agreement took effect during the second quarter of 2015 for 12,580 gross barrels per day over an initial five-year term. The second agreement is anticipated to take effect during the fourth quarter of 2016 for 15,000 gross barrels per day over an initial seven-year term. The aggregate financial commitment fee is approximately $503.7 million at December 31, 2015. While the volume commitment may be met with Company volumes or third-party volumes, the

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Company may be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments.

Productive Wells

The following table sets forth the number of producing oil and natural gas wells in which we owned a working interest at December 31, 2015.

| | Oil(2) | | Natural Gas(1) | | Total(2) | | Operated(2) | |
|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Rocky Mountain | 682 | 579.4 | — | — | 682 | 579.4 | 604 | 565.4 |
| Mid-Continent | 294 | 254.1 | — | — | 294 | 254.1 | 288 | 254.1 |
| Total(2) | 976 | 833.5 | — | — | 976 | 833.5 | 892 | 819.5 |

(1) All gas production is associated gas from producing oil wells.
(2) Count came from internal production reporting system.

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, 2015 for each of the areas where we operate along with the PV-10 values of each. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

| | Developed Acres | | Undeveloped Acres | | Total Acres | | |
|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | PV-10 |
| Rocky Mountain | 67,501 | 56,673 | 42,804 | 26,589 | 110,305 | 83,262 | $ 247,811 |
| Wattenberg Field | 59,752 | 48,924 | 31,487 | 19,698 | 91,239 | 68,622 | 246,148 |
| Other Rocky Mountain | 7,749 | 7,749 | 11,317 | 6,891 | 19,066 | 14,640 | 1,663 |
| Mid-Continent | 8,736 | 7,055 | 6,110 | 4,282 | 14,846 | 11,337 | 80,005 |
| Dorcheat Macedonia Field | 4,985 | 3,482 | 2,180 | 1,153 | 7,165 | 4,635 | 68,509 |
| Other Mid-Continent | 3,751 | 3,573 | 3,930 | 3,129 | 7,681 | 6,702 | 11,496 |
| Total | 76,237 | 63,728 | 48,914 | 30,871 | 125,151 | 94,599 | $ 327,816 |

Undeveloped acreage

We critically review and consider at-risk leasehold with attention to either convert term leasehold to held by production status or through term extensions primarily within the core fields of development where reserve bookings are prevalent. Decisions to expire leasehold generally reside in areas out of our core fields of development or do not pose relevant impacts to development plans or reserves in terms of net acres allowed to expire.

The following table sets forth the number of net undeveloped acres as of December 31, 2015 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 2016 | | Expiring 2017 | | Expiring 2018 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Rocky Mountain | 10,954 | 5,897 | 4,523 | 4,090 | 3,481 | 2,645 |
| Mid-Continent | 604 | 377 | 266 | 174 | 202 | 8 |
| Total | 11,558 | 6,274 | 4,789 | 4,264 | 3,683 | 2,653 |

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Drilling Activity

The following table describes the exploratory and development wells we drilled and completed during the years ended December 31, 2015, 2014 and 2013.

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2015 | | 2014 | | 2013 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Exploratory | | | | | | |
| Productive Wells | — | — | — | — | — | — |
| Dry Wells | 2 | 1.8 | — | — | 1 | 1 |
| Total Exploratory | 2 | 1.8 | — | — | 1 | 1 |
| Development | | | | | | |
| Productive Wells | 92 | 76.1 | 142 | 124.3 | 117 | 102.7 |
| Dry Wells | 2 | 1.4 | — | — | — | — |
| Total Development | 94 | 77.5 | 142 | 124.3 | 117 | 102.7 |
| Total | 96 | 79.3 | 142 | 124.3 | 118 | 103.7 |

The following table describes the present operated drilling activities as of December 31, 2015.

| | As of December 31, 2015 | |
|---|---|---|
| | Gross | Net |
| Exploratory | | |
| Rocky Mountain | — | — |
| Mid-Continent | — | — |
| Total Exploratory | — | — |
| Development | | |
| Rocky Mountain | 9 | 7.7 |
| Mid-Continent | — | — |
| Total Development | 9 | 7.7 |
| Total | 9 | 7.7 |

Capital Expenditure Budget

Our anticipated capital budget for 2016 ranges from $40.0 million to $50.0 million. We plan to spend $35.0 million to $40.0 million, or 89%, of our total budget in the first quarter of 2016 in the Rocky Mountain region to drill nine wells, two extended reach laterals and seven standard reach laterals, and complete 12 wells, four medium reach laterals and eight standard reach laterals, in the Wattenberg Field and participate in the completion of three non-operated wells. In the Mid Continent region, we plan to spend approximately $3.5 million during 2016 to perform approximately 38 recompletions with the remaining $1.5 million planned for corporate expenditures. Further budget guidance for the remainder of 2016 will be determined based upon the final outcome of our divestiture processes. Please refer to Note 3 - Assets Held for Sale in Part II, Item 8 of this Annual Report on Form 10-K, for additional discussion. If commodity prices do not increase significantly or if our properties held for sale are not sold, we plan to cease drilling at the end of first quarter 2016. The ultimate amount of capital we will expend may fluctuate materially based on, among other things, market conditions, commodity prices, asset monetizations, the success of our drilling results as the year progresses and changes in the borrowing base under our revolving credit facility.

Derivative Activity

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

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As of December 31, 2015, and through the filing date of this report, we had the following economic derivatives in place, which settle monthly:

| Settlement Period | Derivative Instrument | Total Volumes (Bbls per day) | Average Short Floor Price (Short-Put) | Average Floor Price (Long-Put) | Average Ceiling Price | Fair Market Value of Asset |
|---|---|---|---|---|---|---|
| Oil | | | | | | (in thousands) |
| 2016 | 3-Way Collar | 5,500 | $ 70.00 | $ 85.00 | $ 96.83 | $ 29,566 |
| Total | | | | | | $ 29,566 |

Currently, forward oil prices are below the average price of our short-puts associated with our three-way collars. Should monthly crude oil settlement prices occur below the strike price of our short-puts associated with the Company’s three-way collars, we will receive a payment from our hedging counterparty equal to the difference between the strike prices of the short-put and long-put multiplied by the monthly volume associated with the three-way collar.

We do not apply hedge accounting treatment to any commodity derivative contracts. Settlements on these contracts and adjustments to fair value are shown as a component of derivative gain (loss) in the accompanying consolidated statements of operations and comprehensive income ("accompanying statements of operations"). Please refer to Note 13 - Derivatives in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion on derivatives.

Title to Properties

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

Competition

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

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 76% of our estimated proved reserves as of December 31, 2015 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2015, the daily NYMEX WTI oil spot price ranged from a high of $61.43 per Bbl to a low of $34.73 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $3.29 per MMBtu to a low of $1.53 per MMBtu.

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 material adverse effect on our financial position, results of operations or cash flows.

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Regulation of the Oil and Natural Gas Industry

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

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

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

Regulation of transportation of oil

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

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

Regulation of transportation and sales of natural gas

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

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

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FERC issued a series of orders in 1996 and 1997 to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

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

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

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

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

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors.

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

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Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the spacing and unitization or pooling of oil and natural gas properties, the regulation of well spacing and well density, and procedures for proper plugging and abandonment of wells. The intent of these regulations is to promote the efficient recovery of oil and gas reserves while reducing waste and protecting correlative rights. Through collaboration with industry through exploration and development operations these regulations effectively identify where wells can be drilled, well densities by geologic formation along with the proper spacing and pooling unit size to effectively drain the resources. Operators can apply for exceptions to such regulations including applications to increase well densities to more effectively recover the oil and gas resources. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

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

Regulation of derivatives and reporting of government payments

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) was passed by Congress and signed into law in July 2010. The Dodd-Frank Act is designed to provide a comprehensive framework for the regulation of the over-the-counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd-Frank Act subjects swap dealers and major swap participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users. In addition, in August 2012, the SEC issued a final rule under Section 1504 of the Dodd-Frank Act, Disclosure of Payment by Resource Extraction Issuers, which would have required resource extraction issuers, such as us, to file annual reports that provide information about the type and total amount of payments made for each project related to the commercial development of oil, natural gas, or minerals to each foreign government and the federal government. In July 2013, the U.S. District Court for the District of Columbia vacated the rule, and the SEC has announced it will not appeal the court’s decision. In December 2015, the SEC proposed revised resource extraction payments disclosure rules that if issued will be applicable to our business.

Environmental, Health and Safety Regulation

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

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

Hazardous substances and waste handling

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on

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certain classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these potentially “responsible persons” may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances but we are not aware of any liabilities for which we may be held responsible that would materially and adversely affect us.

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

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

In addition, other laws require the reporting on use of hazardous and toxic chemicals. For example, in October 2015, EPA granted, in part, a petition filed by several national environmental advocacy groups to add the oil and gas extraction industry to the list of industries required to report releases of certain “toxic chemicals” under the Toxic Release Inventory (“TRI”) program under the Emergency Planning and Community Right-to-Know Act. EPA determined that natural gas processing facilities may be appropriate for addition to TRI applicable facilities and will conduct a rulemaking process to propose such action.

Pipeline safety and maintenance

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

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. The Pipeline Safety, Regulatory Certainty, and Job Creation Act was signed into law in early 2012. In addition, the

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Pipeline and Hazardous Materials Safety Administration (“PHMSA”) has issued new rules to strengthen federal pipeline safety enforcement programs. In 2015, PHMSA proposed to expand its regulations in a number of ways, including through the increased regulation of gathering lines, even in rural areas.

Air emissions

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

For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all “other” fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the “other” wells must use reduced emission completions, also known as “green completions,” with combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2014. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA issued revised rules in 2013 and 2014 in response to some of these requests. Specifically, on September 23, 2013, the EPA published a final amendment extending the compliance dates for certain groups of storage vessels to April 15, 2014 and April 15, 2015, and on December 31, 2014, the EPA issued a final amendment clarifying certain reduced emission completion requirements. Most recently, as part of the reconsideration, EPA proposed amendments to the NSPS rules focused on achieving additional methane and volatile organic compound reductions from oil and natural gas operations. Among other things, EPA has proposed new requirements for leak detection and repair, control requirements for oil well completions, replacement of certain pneumatic equipment, and additional control requirements for gathering, boosting, and compressor stations.

On October 1, 2015, EPA finalized its rule lowering the existing 75 part per billion ("ppb") national ambient air quality standard ("NAAQS") for ozone under the CAA to 70 ppb. Also in 2015, the State of Colorado received a bump-up in its existing ozone non-attainment status from “marginal” to “moderate.” Oil and natural gas operations in ozone nonattainment areas, including in Colorado, may be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. In addition, in February 2014, the Colorado Department of Public Health and Environment’s Air Quality Control Commission (“AQCC”) adopted new and revised air quality regulations that impose stringent new requirements to control emissions from existing and new oil and gas facilities in Colorado. The proposed regulations include new control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in Colorado. For example, the new regulations impose Storage Tank Emission Management (“STEM”) requirements for certain new and existing storage tanks. The STEM requirements require us to install costly emission control technologies as well as monitoring and recordkeeping programs at most of our new and existing well production facilities. The new Colorado regulations also impose a Leak Detection and Repair (“LDAR”) program for well production facilities and compressor stations. The LDAR program primarily targets hydrocarbon (i.e., methane) emissions from the oil and gas sector in Colorado and represents a significant new use of state authority regarding these emissions.

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

Climate change

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit requirements for certain large stationary sources that include potential major sources of GHG emissions. In June 2014, the United States Supreme Court ruled in Utility Air Regulatory Group v. EPA, No. 12 1146. The Supreme Court upheld part of EPA's GHG-related regulations but struck down other portions of the rules. Specifically, the Supreme Court ruled that sources subject to the PSD or Title V programs because of non-GHG emissions could still potentially be subject to certain "best available control technology" requirements applicable to their GHG emissions. Under the Court's opinion, sources subject to the PSD or Title V programs due solely to their GHG emissions, however, can no longer be subject to EPA's GHG permitting requirements. The D.C. Circuit issued an amendment judgment following remand, and EPA intends to conduct future rulemaking to make revisions conforming to the court rulings. EPA also published a proposed rule regarding source determination, including proposals to define the term "adjacent" under the CAA in 2015, which could affect how major sources, including GHG major sources, are regulated. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHGs from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has, from time to time, considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Most recently, the EPA finalized rules to further reduce GHG emissions, primarily from coal-fired power plants, under its Clean Power Plan. If fully implemented, the Clean Power Plan could affect the demand for products we supply or otherwise affect our operations. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. President Obama has indicated that climate change and GHG regulation remains a significant priority for his second term as reflected most recently in the agreement reached during the December 2015 United Nations climate change conference to reduce 26-28% of United States' GHG emissions by 2025 against a 2005 baseline. The President also issued a Climate Action Plan in June 2013, calling for, among other things, a reduction in methane emissions from the oil and gas industry. In January 2015, the EPA announced a comprehensive strategy intended to further reduce methane emissions from the oil and gas sector, which already has resulted in the proposed amendments to the 2012 NSPS noted above and may result in additional regulation. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce.

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

Water discharges

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

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

Endangered Species Act

The federal Endangered Species Act restricts activities that may affect endangered and threatened species or their habitats. A final rule amending how critical habitat is designated was finalized in 2016. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

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

Hydraulic fracturing

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

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

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

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Federal agencies are also considering additional regulation of hydraulic fracturing. The EPA has published guidance for issuing underground injection permits that would regulate hydraulic fracturing using diesel fuel. This guidance eventually could encourage other regulatory authorities to adopt permitting and other restrictions on the use of hydraulic fracturing. In addition, on October 21, 2011, the EPA announced its intention to propose regulations under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. In April 2015, EPA proposed regulations that would address discharges of wastewater pollutants from onshore unconventional extraction facilities to publicly-owned treatment works. The EPA is also collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. The EPA issued a progress report regarding the study in December 2012, which described generally the continuing focus of the study, but did not provide any data, findings, or conclusions regarding the safety of hydraulic fracturing operations. In June 2015, EPA released a draft assessment of the potential impacts to drinking water resources from hydraulic fracturing. The Agency will finalize the assessment following public comment and review. The results of this study could result in additional regulations, which could lead to operational burdens similar to those described above. The EPA also has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act ("TSCA") to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to the TSCA rulemaking. On January 7, 2015, several national environmental advocacy groups filed a lawsuit requesting that the EPA add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" under EPA's Toxics Release Inventory ("TRI") program. The United States Department of the Interior also finalized a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. This rule has been stayed pending the outcome of ongoing litigation. In early 2016, the Bureau of Land Management ("BLM") proposed rules related to further controlling the venting and flaring of natural gas on BLM land. And the U.S. Occupational Safety and Health Administration has proposed stricter standards for worker exposure to silica, which would apply to use of sand as a proppant for hydraulic fracturing. In addition, the Department of Labor and the Department of Justice, Environment and Natural Resources Division released a Memorandum of Understanding announcing an inter-agency effort to increase the enforcement of workplace safety crimes that occur in conjunction with environmental crimes.
Apart from these ongoing federal and state initiatives, local governments are adopting new requirements on hydraulic fracturing and other oil and gas operations. For example, voters in the cities of Fort Collins, Boulder and Lafayette, Colorado recently approved bans of varying lengths on hydraulic fracturing within their respective city limits. In 2014, Boulder and Larimer county lower courts overturned the bans. The cities of Longmont and Fort Collins appealed the decisions. In 2015, the Colorado Supreme Court heard oral arguments on these appeals and a decision is expected in the first half of 2016. In addition, New York recently enacted a permanent moratorium on all hydraulic fracturing activities, which became final in June 2015. Any successful bans or moratoriums where we operate could increase the costs of our operations, impact our profitability, and even prevent us from drilling in certain locations.
At this time, it is not possible to estimate the potential impact on our business of recent state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing. The adoption of future federal, state or local laws or implementing regulations imposing new environmental obligations on, or otherwise limiting, our operations could make it more difficult and more expensive to complete oil and natural gas wells, increase our costs of compliance and doing business, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products and services. We cannot assure you that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations.
Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in both the Rocky Mountains and Mid-Continent. In both the Rocky Mountains and the Mid-Continent, other companies in the oil and gas industry have significantly more experience than we do using hydraulic fracturing. Typical hydraulic fracturing treatments are made up of water, chemical additives and sand. We utilize major hydraulic fracturing service companies who track and report all additive chemicals that are used in fracturing as required by the

appropriate government agencies. Each of these companies fracture stimulate a multitude of wells for the industry each year. For as long as we have owned and operated properties subject to hydraulic fracturing, there have not been any material incidents, citations or suits related to fracturing operations or related to environmental concerns from fracturing operations.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. We adhere to applicable legal requirements and industry practices for

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groundwater protection. Our operations are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), who frequently inspect our fracturing operations.

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

National Environmental Policy Act

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

Oil Pollution Act

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

State laws

Our properties located in Colorado are subject to the authority of the Colorado Oil and Gas Conservation Commission (the "COGCC"), as well as other state agencies. The COGCC recently approved new rules regarding minimum setbacks, groundwater monitoring, large-scale facilities in urban mitigation areas, and public notice requirements that are intended to prevent or mitigate environmental impacts of oil and gas development and include the permitting of wells. Over the past several years, the COGCC has also approved new rules regarding various other matters, including wellbore integrity, hydraulic fracturing, well control waste management, spill reporting, and an increase in potential sanctions for COGCC rule's violations. Depending on how these and any other new rules are applied, they could add substantial increases in well costs for our Colorado operations. The rules could also impact our ability and extend the time necessary to obtain drilling permits, which would create substantial uncertainty about our ability to meet future drilling plans and thus production and capital expenditure targets. The State of Colorado also created a task force to make recommendations for minimizing land use and other conflicts concerning the location of new oil and gas facilities. In February 2015, the task force concluded their deliberations and agreed upon nine consensus proposals which were sent to Governor Hickenlooper for his review. Three of the proposals require further legislative action, while the other six proposals require rulemaking or other regulatory action. The proposals support (i) a senate bill that would postpone expiration of recently adopted regulations, regarding air emissions; (ii) tasking the COGCC with crafting new rules related to siting of "large-scale" pads and facilities; (iii) requiring the industry to provide advance information about development plans to local governments; (iv) improving the COGCC's local government liaison and designee programs; (v) adding 11 full-time staffers to the COGCC; (vi) bolstering the inspection staff and equipment for monitoring oil and gas facility air emissions and setting up a hotline for citizen health complaints at the Colorado

Department of Public Health and Environment; (vii) creating a statewide oil and gas information clearinghouse; (viii) studying ways to ameliorate the impact of oil and gas truck traffic and (ix) creating a compliance-assistance program at the COGCC to help operators comply with the state's changing rules and ensure consistent enforcement of rules by state inspectors. A number of additional proposals did not receive sufficient task force support to be included with the nine consensus proposals, but may nevertheless be forwarded to the Governor as well.

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In 2015 and into 2016, COGCC began a rulemaking to implement two of these recommendations (in particular items (ii) and (iii) identified above). With respect to recommendation (ii) above, the COGCC finalized rules to permit "large-scale facilities" in "urban mitigation areas." With respect to recommendation (iii) above, the COGCC finalized rules to require operators to provide certain municipalities with public notice prior to engaging in operations. Both rules will become effective later this year.

Employees

As of December 31, 2015, we employed 282 people and also utilize the services of independent contractors to perform various field and other services. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Offices

As of December 31, 2015, we leased 83,463 square feet of office space in Denver, Colorado at 410 17th Street where our principal offices are located and leased 1,635 square feet in Kersey, Colorado, where we have a field office. We also own field offices in Evans, Colorado and Magnolia, Arkansas.

Available information

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

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

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

Item 1A. Risk Factors.

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

Risks Related to Our Business

Continuation of the recent declines, or further declines, in oil and, to a lesser extent, natural gas prices, will adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations or targets and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas and NGLs, heavily influences our revenue, profitability, cash flows, liquidity, borrowing base under our revolving credit facility, access to capital, present value and quality of our reserves, the nature and scale of our operations and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. In recent years, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 76% of our estimated proved reserves as of December 31, 2015 were oil and NGLs, our financial results are more sensitive to movements in oil prices. Since mid-2014, the price of crude oil has significantly declined. As a result, we experienced significant decreases in crude oil revenues and recorded asset impairment charges due to commodity price declines. If commodity prices do not increase significantly or if our properties held for sale are not sold, we plan to cease drilling at the end of the first quarter 2016. A prolonged period of low market prices for oil, natural gas and NGLs, like the

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current commodity price environment, or further declines in the market prices for oil and natural gas, will result in capital expenditures being further curtailed and will adversely affect our business, financial condition and liquidity and our ability to meet obligations, targets or financial commitments and could ultimately lead to restructuring or filing for bankruptcy, which would have a material adverse effect on our stock price and indebtedness. Additionally, lower oil, natural gas, and NGL prices may cause further decline in our stock price. During the year ended December 31, 2015, the daily NYMEX WTI oil spot price ranged from a high of $61.43 per Bbl to a low of $34.73 per Bbl and the NYMEX natural gas HH spot price ranged from a high of $3.29 per MMBtu to a low of $1.53 per MMBtu. As of February 23, 2016, the daily NYMEX WTI oil spot price and NYMEX natural gas HH spot price was $30.07 per Bbl and $1.83 per MMBtu, respectively.

The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions from members of the Organization of Petroleum Exporting Countries and other oil producing nations;
- 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;
- the price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption;
- the availability of pipeline capacity and infrastructure; and
- the price and availability of alternative fuels.

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

- reduction of our revenues, profit margins, operating income and cash flows;
- reduction in the amount of crude oil, natural gas and NGLs that we can produce economically and may lead to reduced liquidity and the inability to pay our liabilities as they come due;
- certain properties in our portfolio becoming economically unviable;

- delay or postponement of some of our capital projects;
- further reduction of our 2016 capital program, or significant reductions in future capital programs, resulting in a reduced ability to develop our reserves;
- limitations on our financial condition, liquidity and/or ability to finance planned capital expenditures and operations;
- reduction to the borrowing base under our revolving credit facility or limitations in our access to sources of capital, such as equity or debt;

- declines in our stock price;
- refinery industry demand for crude oil;
- storage availability for crude oil;
- the ability of our vendors, suppliers, and customers to continue operations due to the prevailing adverse market conditions;
- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment; and
- additional counterparty credit risk exposure on commodity hedges.

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

Oil and natural gas prices are volatile and the Company has a limited portion of its anticipated production hedged in 2016. As our hedges expire, more of our future production will be sold at market prices, exposing us to the fluctuations in the price of oil and natural gas, unless we enter into hedging transactions. To the extent that the price of oil and natural gas remains at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges and our results of operations and financial condition would be materially adversely impacted.

In 2016, we have 5,500 Bbls/d of oil hedged with three-way collars with an average ceiling of $96.83/Bbl, average floor of $85.00/Bbl and average short floor of $70.00/Bbl. These hedges may be inadequate to protect us from continuing and prolonged declines in the price of oil and natural gas. Currently, oil and natural gas prices are trading below the average prices of our short floors associated with our three-way collars. To the extent that future monthly settlement prices are below our short floor prices, we will realize the settlement price plus the difference between our short floor and floor prices. Therefore, additional risk is associated with these three-way collar contracts in a declining commodity price environment relative to fixed price swaps and collars. See the Derivative Activity section in Part I, Item I of this Annual Report on Form 10-K for a summary of our hedging activity.

Due to reduced commodity prices and lower operating cash flows we may be unable to maintain adequate liquidity and our ability to make interest payments in respect of our indebtedness could be adversely affected.

Recent declines in commodity prices have caused a reduction in our available liquidity and we may not have the ability to generate sufficient cash flows from operations and, therefore, sufficient liquidity to meet our anticipated working capital, debt service and other liquidity needs. In order to increase our liquidity to levels sufficient to meet our commitments, we are currently pursuing or considering a number of actions including (i) dispositions of non-core assets, (ii) minimizing our capital expenditures, (iii) issuing of new debt or equity, (iv) effectively managing our working capital and (v) improving our cash flows from operations. There can be no assurance that sufficient liquidity can be raised from one or more of these transactions or that these transactions can be consummated within the period needed to meet certain obligations. Furthermore, we cannot assure you that any of our strategies will yield sufficient funds to meet our working capital or other liquidity needs, including for payments of interest and principal on our debt in the future, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European, Asian and the United States financial markets have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have precipitated an economic slowdown. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United

States or abroad deteriorates, worldwide demand for petroleum products could diminish

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further, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

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

As of December 31, 2015, we had $500.0 million of outstanding 6.75% Senior Notes due 2021 (“6.75% Senior Notes”), $300.0 million of outstanding 5.75% Senior Notes due 2023 (“5.75% Senior Notes” and, together with the 6.75% Senior Notes, the “Senior Notes”), $79.0 million outstanding under our revolving credit facility and $21.3 million of cash and cash equivalents. At this time, we intend to fund our capital expenditures through our cash flow from operations and borrowings under our revolving credit facility, but continuation of the recent declines, or further declines in commodity prices coupled with our financing needs may require us to seek additional equity, debt, or project-level financing. Our level of indebtedness could affect our operations in several ways, including the following:

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

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

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

Our ability to borrow under our revolving credit facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio, a maximum leverage ratio and a minimum interest coverage ratio. As of December 31, 2015, the Company was in compliance with all financial covenants, with a senior secured debt to EBITDAX ratio of 0.3x, an interest coverage ratio of 4.8x and a current ratio of 3.5x. However, continuation of low oil, natural gas and NGL prices or their further deterioration could significantly reduce cash flow, which is a critical underpinning of our required financial covenants, which could make it necessary for us to negotiate an amendment to one or more of these financial covenants in order to avoid a default. However, there is no guarantee that we would be successful in negotiating such an amendment with our lenders.

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

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

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We would not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. As of December 31, 2015 and through the filing date of this report, we were in compliance with all financial and non-financial covenants. There is the possibility that if we do not dispose of some assets or execute upon one or more of our other 2016 liquidity strategies, we will violate our revolving credit facility covenants by the end of 2016. If any event of default exists under the revolving credit facility, the lenders will be able to accelerate the maturity of the loan and exercise other rights and remedies.

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

A downgrade in our debt or credit ratings could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

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Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

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

The borrowing base under our revolving credit facility is redetermined at least semi-annually, and up to one additional time between scheduled determinations upon request of the Company or lenders holding $66^2/_3$% of the aggregate commitments. In October 2015, our borrowing base was redetermined from \$550.0 million to \$475.0 million, and our next scheduled redetermination is in May 2016. 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. Given the current commodity pricing environment, we are expecting further reductions to our borrowing base. 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.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves below. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors, including, but not limited to, the following, may result in substantial losses, including personal injury or loss of life, penalties, damage or destruction of property and equipment, and curtailments, delays or cancellations of our scheduled drilling projects:

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

- delays imposed by or resulting from compliance with regulatory requirements, such as permitting delays;
- proximity to and capacity of transportation facilities;
- title problems;
- safety concerns, and

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•limitations in the market for oil and natural gas.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See Estimated Proved Reserves under Part I, Item 1 of this Annual Report on Form 10-K for information about our estimated oil and natural gas reserves and the PV-10 (a non-GAAP financial measure) as of December 31, 2015, 2014 and 2013.

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 this 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, and given the current volatility in pricing, such assumptions are difficult to make. Although the reserve information contained herein is reviewed by independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise particularly as they relate to state-of-the-art technologies being employed such as the combination of hydraulic fracturing and horizontal drilling.

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

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

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

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

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

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2015, 2014 and 2013, we based the estimated discounted future net revenues from our proved reserves on the unweighted arithmetic average of the first-day-of-the-month commodity prices (after adjustment for location and quality differentials) for the preceding twelve months, without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas and hedging instruments;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- the amount and timing of future development costs;
- the supply and demand of oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor (the factor required by the SEC) used when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.
Because market prices for oil at the end of 2015 were significantly lower than the average price for the year determined under SEC rules, the actual future prices and costs will likely differ materially from those used in the present value estimates included in this Annual Report on Form 10-K. Moreover, the lower prices at the end of 2015 may be more reflective of future economic conditions since prices have fallen further in 2016. If oil and natural gas SEC prices declined by 10% then our PV-10 value as of December 31, 2015 would decrease by approximately 12% or $39.5 million. The PV-10 of our Rocky Mountain region, primarily our Wattenberg assets, would decrease by 9.5% or $23.5 MM. Please refer to Estimated Proved Reserves under Part 1, Item 1 of this Annual Report on Form 10-K for management’s discussion of this non-GAAP financial measure.

As a result of the sustained decrease in prices for oil, natural gas and NGLs, we have taken write-downs of the carrying value of our properties and may be required to take further write-downs if oil and natural gas prices remain depressed or decline further or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our drilling results.

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, from time to time, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. Oil, natural gas and NGL prices have significantly declined since mid-2014 and have remained depressed into 2016. Primarily as a result of these low commodity prices, we recorded a $740.5 million impairment of oil and gas properties for the year ended December 31, 2015. Additionally, given the history of price volatility in the oil and natural gas markets, prices could remain depressed or decline further or other events may arise that would require us to record further impairments of the book values associated with oil and natural gas properties. Accordingly, we may incur significant impairment charges in the future which could have a material adverse effect on our results of operations and could reduce our earnings and stockholders’ equity for the periods in which such charges are taken.

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

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

- landing our well bore in the desired drilling zone;

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

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

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, limited takeaway capacity or depressed natural gas and oil prices, the return on our investment in these areas may not be as attractive as anticipated. Further, as a result of any of these developments, we could incur material impairments 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 and may lead to reduced liquidity and the inability to pay our liabilities as they come due.

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

our oil and natural gas reserves or anticipated production volumes.
Our exploration, development and exploitation activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Our cash flows used in investing activities, excluding derivative cash settlements, were $452.6 million, of which, $454.3 million (including $28.3 million for the acquisition of oil and gas properties and contractual obligations for land

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acquisitions) was related to capital and exploration expenditures for the year ended December 31, 2015. Our capital expenditure budget for 2016 ranges from $40.0 million to $50.0 million. If commodity prices do not increase significantly or if our properties held for sale are not sold, we plan to cease drilling at the end of the first quarter of 2016. 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.

At this time, we intend to finance our future capital expenditures primarily through cash flows provided by operating activities and borrowings under our revolving credit facility. However, continuation of the recent declines, or further declines in commodity prices coupled with our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional equity securities, debt securities or the strategic sale of assets. The issuance of additional debt may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under our revolving credit facility would be reduced. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.
Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

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

If the borrowing base under our revolving credit facility or our revenues continue to 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. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all, and we may be unable to complete the strategic sale of assets. 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 undeveloped leases and a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations may lead to reduced liquidity and the inability to pay our liabilities as they come due.
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, render us unable to replace reserves and production and place us at a competitive disadvantage.
Concentration of our operations in a few core areas may increase our risk of production loss.

Our assets and operations are concentrated in two core areas: the Wattenberg Field in Colorado and the Dorcheat Macedonia Field in southern Arkansas. These core areas currently provide approximately 99% of our current sales volumes and the vast majority of our development projects. Additionally, if we are able to successfully execute upon the sale of our Arkansas assets that are currently held for sale, our assets and operations will be solely concentrated in one core area in the Wattenberg Field which would further increase our risk of production loss.

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The Wattenberg and Dorcheat Macedonia Fields represent 81% and 18%, respectively, of our 2015 total sales volumes. Because our operations are not as diversified geographically as some of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including: fluctuations in prices of crude oil, natural gas and NGLs produced from wells in the area, accidents or natural disasters, restrictive governmental regulations and curtailment of production or interruption in the availability of gathering, processing or transportation infrastructure and services, and any resulting delays or interruptions of production from existing or planned new wells. For example, recent increases in activity in the Wattenberg Field have contributed to bottlenecks in processing and transportation that have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field, we are subject to increasing competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages or delays. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

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

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

We do not operate all of the properties in which we have an interest. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator’s breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the timing and amount of capital expenditures, the available expertise and financial resources, the inclusion of other participants and the use of technology. Our lack of control over non-operated properties also makes it more difficult for us to forecast capital expenditures, revenues, production and related matters.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production getting to market. The marketability of our oil and natural gas and production, particularly from our wells located in the Wattenberg Field, depends in part on the availability, proximity and capacity of gathering, processing, pipeline, trucking and rail systems. The amount of oil and natural gas that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, maintenance, weather, field labor issues or disruptions in service. Curtailments and disruptions in these systems may last from a few days to several months. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. These risks are greater for us than for some of our competitors because our operations are focused on areas where there is currently a substantial amount of development activity, which increases the likelihood that there will be periods of time in which there is insufficient midstream capacity to accommodate the resulting increases in production. For example, in 2014 and the first half of 2015, the principal third-party provider we use in the Wattenberg Field experienced periods of high line pressures and was forced to periodically shut down due to oxygen in the line and for other unscheduled repairs. The resulting capacity constrained our production and reduced our revenue from the affected wells. In addition, we might voluntarily curtail production in response to market conditions. Any significant curtailment in gathering, processing or pipeline system capacity, significant delay in the construction of necessary facilities or lack of availability of transport, would interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations, and the expected results of our drilling program.

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

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

Approximately 49% of our total proved reserves were classified as proved undeveloped as of December 31, 2015. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate or that may be available to us. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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

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

According to estimates included in our December 31, 2015 proved reserve report, if, on January 1, 2016, 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 40% during the first year. If we fail to replace reserves through drilling, our level of production and cash flows will be affected adversely.

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

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

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

- natural disasters.

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Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

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

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

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

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

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

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10-K. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional evaluation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. Prior to drilling, the use of 2-D and 3-D seismic technologies, various other technologies and the study of producing fields in the same area will not enable us to know conclusively whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. In addition, the use of 2-D and 3-D seismic data and other technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures which may result in a reduction in our returns or increase our losses. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill any dry holes in our current and future drilling locations, our profitability and the value of our properties will likely be reduced. We cannot assure you that the analogies we

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draw from