# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# Form 10-K

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

**For the fiscal year ended December 31, 2020**

**OR**

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

**Commission file number: 001-35371**

# Bonanza Creek Energy, Inc.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **61-1630631** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. employer identification number) |
| **410 17th Street, Suite 1400** | |
| **Denver, Colorado** | **80202** |
| (Address of principal executive offices) | (Zip Code) |

**(720) 440-6100**
(Registrant's telephone number, including area code)

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

| (Title of Class) | (Trading Symbol) | (Name of Exchange) |
|---|---|---|
| Common Stock, par value $0.01 per share | BCEI | New York Stock Exchange |

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

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

Large Accelerated Filer ☐ Accelerated Filer ☒ Non-accelerated Filer ☐ Smaller Reporting Company ☐ Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates on June 30, 2020, based upon the closing price of $14.82 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $271.4 million. Excludes approximately 2.5 million 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 15, 2021: 20,839,227

**Documents Incorporated By Reference:**

Portions of the registrant's definitive proxy statement, will be filed with the Securities and Exchange Commission within 120 days of December 31, 2020, as incorporated by reference into Part III of this report for the year ended December 31, 2020.

**BONANZA CREEK ENERGY, INC.**
**FORM 10-K**
**FOR THE YEAR ENDED DECEMBER 31, 2020**

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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 (the "Exchange Act"). When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project," "plan," "will," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

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

- the Company's business strategies;
- reserves estimates;
- estimated sales volumes;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- ability to modify future capital expenditures;
- anticipated costs;
- compliance with debt covenants;
- ability to fund and satisfy obligations related to ongoing operations;
- compliance with government regulations, including environmental, health, and safety regulations and liabilities thereunder;
- 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;
- impact of any pandemic or other public health epidemic, including the ongoing COVID-19 pandemic;
- natural gas, oil, and natural gas liquid prices and factors affecting the volatility of such prices;
- impact of lower commodity prices;
- sufficiency of impairments;
- 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;
- impact of potentially disruptive technologies;
- our estimated revenue gains and losses;
- the timing and success of specific projects;
- our implementation of standard and long reach laterals;
- 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;
- stated 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, C, and Codell benches in our legacy, French Lake, and northern acreage;

- our ability to replace oil and natural gas reserves;
- our ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking;
- 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;
- the expected timetable for completing the announced merger of the Company with HighPoint Resources Corporation (the “Transaction”), the results, effects, benefits and synergies of the Transaction, future opportunities for the combined company, other plans and expectations with respect to the Transaction, and the anticipated impact of the Transaction on the combined company’s results of operations, financial position, growth opportunities and competitive position; 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;
- the effects of disruption of our operations or excess supply of oil and natural gas due to the COVID-19 pandemic and the actions by certain oil and natural gas producing countries;
- the scope, duration and severity of the COVID-19 pandemic, including any recurrence, as well as the timing of the economic recovery following the pandemic;
- 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;
- 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 and completion 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;
- operational interruption of centralized gas and oil processing facilities;
- competition in the oil and natural gas industry;
- management's ability to execute our plans to meet our goals;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;
- access to adequate gathering systems and pipeline take-away capacity;
- our ability to secure adequate processing capacity for natural gas we produce, to secure adequate transportation for oil, natural gas, and natural gas liquids we produce, and to sell the oil, natural gas, and natural gas liquids 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, South America, 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."* 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 deposited via water accumulate.

*"Completion."* The process of stimulating a drilled well followed by the installation of permanent equipment to allow for the production of crude oil and/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 acres."* 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 vapor 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 price 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 cash 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.

*"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, 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.

*"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.

*"Gross Wells."* The total wells in which an entity owns a working interest.

*"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 into the wellbore.

*"Infill drilling."* The addition of wells in a field that decreases average well spacing.

*"LIBOR."* London interbank offered rate.

*"LOE."* Lease operating expense.

*"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.

*“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.”* The sealing off of all gas and liquids in the strata penetrated by a well so that the gas and liquids from one stratum will not escape into another stratum or to the surface.

*“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.

(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 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 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.

"*Reclamation."* The process to restore the land and other resources to their original state prior to the effects of oil and gas development.

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

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

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

*"Reservoir."* A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

*"Resource play."* 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 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. Typical spacing for unconventional wells is either 640 acres or 1,280 acres for both oil and gas.

*"Standard reach lateral equivalent well."* Equates to a ratio of one well to one well for a standard reach lateral well, one and half wells to one well for a medium reach lateral well, and two wells to one well for an extended reach lateral well. Standard reach laterals typically include lengths of up to one mile, medium reach laterals of up to one and a half miles, and extended reach laterals of up to two miles.

*"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.

# 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 Denver-based exploration and production company focused on the acquisition, development, and extraction of oil and associated liquids-rich natural gas in the United States. The Company's oil and liquids-weighted assets and operations are concentrated in the rural portions of the Wattenberg Field in Colorado. Our development and extraction activities are primarily directed at the horizontal development of the Niobrara and Codell formations in the Denver-Julesburg (“DJ”) Basin. The majority of our revenues are generated through the sale of oil, natural gas, and natural gas liquids production.

We operate approximately 84% of all our productive wells, allowing us to control the pace, costs, and completion techniques used in the development of our reserves. The Wattenberg Field has a low cost structure, mature infrastructure, strong production efficiencies, multiple producing horizons, multiple service providers, established reserves, and prospective drilling opportunities, which helps facilitate predictable production and reserve growth.

Although commodity prices have improved slightly over the last few months, the challenging commodity price environment continues to be volatile. Nevertheless, we believe we remain well-positioned in this environment due to our debt-free balance sheet, ample liquidity, inventory of economic drilling locations, low operating costs, and our operational flexibility, which allows us to respond to commodity price fluctuations.

During 2020, we demonstrated our operational focus on achieving best-in-class execution by lowering our cost of operations on a per unit basis. We increased drilling efficiencies and improved well performance via enhanced completion designs, which contributed to the growth of our reserves and production. Additionally, we maintained our conservative balance sheet and paid our reserve-based credit facility to a zero balance, thereby providing substantial available liquidity. We intend to continue our operational focus in 2021, emphasizing responsible growth and development, cost control, and full-cycle returns, with the intent to achieve positive cash flow. We will continue to monitor the ongoing commodity price and regulatory environment and expect to retain the operational flexibility to adjust our drilling and completion plans in response to such conditions.

## Our Business Strategies

The Company’s primary objective is to maximize shareholder returns by responsibly developing our oil and gas resources. We seek to accomplish this through development of existing inventory and value-accretive acquisition and divestiture activity. We seek to balance our production base while achieving positive cash flow. Key aspects of our strategy include:

- *Multi-well pad development across our leasehold.* We believe horizontal development is the most efficient, environmentally responsible, and safest way to recover the hydrocarbons located within our leasehold.
- *Enhanced completions.* We continuously evaluate completion designs to increase well productivity and apply a multivariate regression analysis with the objective of optimizing economic returns. Petrophysical, geological, and geophysical analysis is used in conjunction with spacing evaluations and individualized well designs to increase value of each spacing unit.
- *Continuous safety improvement and strict adherence to health and safety regulations.* Our goal is to utilize industry best practices to meet or exceed regulatory requirements and consistently engage stakeholders in our development planning and operations. We strive to maintain a safe workplace for our employees and contractors at all times.
- *Environmental stewardship.* We constantly strive to control and reduce emissions and seek to comply with all applicable air quality and other environmental rules and regulations. We employ best practices, including pipeline gathering and takeaway as well as vapor recovery and leak detection equipment. Additionally, we work closely with our service providers to help ensure they stay in compliance with environmental regulations when operating on our behalf.

- *Disciplined approach to acquisitions and divestitures.* Opportunities are evaluated in the context of maintaining development flexibility, positive cash flows, and a healthy balance sheet. We pursue value-accretive acquisitions and strive to maximize scale and minimize financial and operational risk.
- *Prudent risk management.* The Company believes a healthy balance sheet, focus on cost control, and minimizing long-term commitments are critical to controlling risk. A low debt profile and judicious use of hedging practices help reduce cash flow volatility. Continually striving to be a cost-efficient operator and maintaining a flexible capital spending program enable us to respond to changing market conditions.

The Company is also committed to continuously improving its environment, social, and governance ("ESG") performance. We work to identify and implement opportunities to minimize our environmental impact. In addition to employing best practices to reduce emissions, generally, our efforts include monitoring and reducing greenhouse gas emissions, and evaluating the risks and opportunities that climate change may present to our business and incorporating them into our business strategy. We invest in our employees by providing regular annual safety training for all employees, hands-on safety training for field employees, and opportunities for professional development across the organization. The Company also plans to conduct regular shareholder outreach efforts focused on a variety of topics, including executive compensation and other ESG issues.

As a further step in these efforts, our Board of Directors recently approved the restructuring of its EHS&RC and Reserves Committee to become its new "ESG Committee." The ESG Committee will be responsible for overseeing and supporting the Company's commitment to environmental, health, and safety, social responsibility, sustainability, and other public policy matters relevant to the Company. (Responsibility for oversight of the Company's processes for estimating and reporting its proved reserves will shift to the Board's Audit Committee.) The ESG Committee will assist senior management in setting the Company's general strategy relating to ESG matters and in developing, implementing, and monitoring initiatives and policies based on that strategy.

**Significant Developments in 2020**

On November 9, 2020, the Company and HighPoint Resources Corporation ("HighPoint") entered into an Agreement and Plan of Merger (the "Merger Agreement"), providing for our acquisition of HighPoint (the "HighPoint Acquisition"). The strategic combination will result in the Company being the leading unconventional oil producer in rural Weld County, significantly increase free cash flow, and maintain economic resilience. The preliminary merger consideration is expected to be $337.4 million, consisting of a combination of the issuance of shares of our common stock and senior notes. The transaction is expected to close in the first half of 2021, contingent upon a number of factors disclosed in the Merger Agreement.

The Company continued its development in the DJ Basin while testing enhanced completion designs on large, efficient multi-well pads throughout the Company's acreage position. Enhanced completion designs varied to ensure that thorough knowledge could be applied to future development programs. Fluid volumes and types, fluid rates, proppant volumes and types, stage spacing, perforation architecture, lateral spacing, and flowback techniques were the primary variables that were tested throughout the 2020 program. Along with extensive internal evaluation, the Company will also continue to monitor industry trends, public data, and information from non-operated wells to further define optimum completion techniques. We deployed one rig in the beginning of 2020 and temporarily discontinued our use of the rig in response to the weakening commodity price environment starting in March 2020. Nevertheless, sales volumes increased by approximately 3% when comparing the fourth quarters of 2020 and 2019.

The Company's 2020 capital program and production came in within guidance at $67.7 million and 25.2 MBoe per day, respectively. During 2020, the Company drilled 14 gross operated wells, completed 9 gross operated wells, turned to sales 26 gross operated wells, and participated in the drilling of 11 gross non-operated wells.

The Company's gathering, treating, and production facilities, maintained under its Rocky Mountain Infrastructure, LLC ("RMI") subsidiary, provide many operational benefits to the Company and cost economies of a centralized system. Additionally, in 2019, the Company installed a new oil gathering line to Riverside Terminal (on the Grand Mesa Pipeline), which resulted in a corresponding $1.25 to $1.50 per barrel reduction to our oil differentials for barrels transported on such gathering line. The total value of reduced oil differentials during the year ended December 31, 2020 was approximately $6.2 million.

The following table summarizes our estimated proved reserves as of December 31, 2020:

| Estimated Proved Reserves | Crude Oil (MBbls) | Natural Gas (MMcf) | Natural Gas Liquids (MBbls) | Total Proved (MBoe) |
|---|---|---|---|---|
| Developed | 24,320 | 123,220 | 14,315 | 59,172 |
| Undeveloped | 28,473 | 112,508 | 11,796 | 59,020 |
| Total Proved | 52,793 | 235,728 | 26,111 | 118,192 |

Total proved reserves as of December 31, 2020 decreased by approximately 3% over the comparable period in 2019.

The following table summarizes our PV-10 reserve value, sales volumes, projected capital spend, and proved undeveloped drilling locations as of December 31, 2020:

| Estimated Proved Reserves at December 31, 2020(1) | | | Average Net Daily Sales Volumes for the Year Ended December 31, 2020 | Projected Q1 2021 Capital Expenditures(4) | Gross Proved Undeveloped Drilling Locations as of December 31, 2020(3) |
|---|---|---|---|---|---|
| Total Proved (MBoe) | % Proved Developed | PV-10 ($ in MM)(2) | (Boe/d) | ($ in millions) | |
| 118,192 | 50 % | $ 437.1 | 25,242 | $ 35.0 - 40.0 | 216 |

(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 $39.57 per Bbl WTI and $1.99 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $4.61 per Bbl for crude oil and a decrease of $1.04 per MMBtu for natural gas.

(2) We believe that PV-10 provides useful and relevant information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies (specifically, the relative monetary significance of our 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 in the "Reserves" subsection of Item 1 below.

(3) The Company has 297.5 standard reach lateral equivalent gross proved undeveloped drilling locations as of December 31, 2020.

(4) The Company is providing guidance for the first quarter of 2021 for Bonanza Creek as a stand-alone company. Additional guidance for 2021 on a combined basis will be provided after the closing of the HighPoint Acquisition.

**Our Operations**

During 2020, our operations were solely focused in the rural portions of the Wattenberg Field in the Rocky Mountain region in Weld County, Colorado, targeting the Niobrara and Codell formations. As of December 31, 2020, our Wattenberg position consisted of approximately 87,000 gross (65,000 net) acres, and our estimated proved reserves were 118,192 MBoe and contributed 25,242 Boe per day of sales volumes during 2020.

The Niobrara and Codell formations are now primarily developed 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 has been delineated on our western legacy acreage. Our northern and southern acreage positions are still being delineated.

As of December 31, 2020, we had a total of 758 gross producing wells, of which 575 were horizontal wells. Our sales volumes for the fourth quarter of 2020 were 25,029 Boe per day. As of December 31, 2020, our working interest for all productive wells averaged approximately 80%, and our net revenue interest was approximately 66%.

We drilled and participated in drilling 25 gross (13.9 net) standard reach lateral ("SRL") equivalent wells in 2020 in the Wattenberg Field. As of December 31, 2020, we have an identified drilling inventory of approximately 216 gross (141.0 net) proved undeveloped ("PUD") drilling locations (297.5 gross SRL equivalents) on our acreage.

The following table summarizes our drilling and completion activity for SRL wells, medium reach lateral wells ("MRL"), and extended reach laterals wells ("XRL") on a gross basis for the year ended December 31, 2020.

| | **SRL** | | **MRL** | | **XRL** | |
|---|---|---|---|---|---|---|
| | **Drilled** | **Completed** | **Drilled** | **Completed** | **Drilled** | **Completed** |
| Niobrara – Operated | 14 | 4 | — | — | — | 5 |
| Codell – Operated | — | — | — | — | — | — |
| Niobrara – Non-operated | 10 | — | — | — | — | — |
| Codell – Non-operated | 1 | — | — | — | — | — |

**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. Our estimated proved reserves for the years ended December 31, 2020, 2019, and 2018 were determined using the preceding twelve month 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 undeveloped properties are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, all of these estimates are expected to change as new information becomes available. Neither prices nor costs have been escalated. The actual quantities and present values of our estimated proved reserves may vary from what we have estimated.

The table below sets forth information regarding our estimated proved reserves, all of which is located in the Wattenberg Field in the Rocky Mountain region, as of December 31, 2020, 2019, and 2018. The proved reserve estimates were prepared by third-party independent reserve engineers Ryder Scott Company, LP. ("Ryder Scott") as of as of December 31, 2020 and by Netherland, Sewell & Associates, Inc. ("NSAI") as of December 31, 2019 and 2018. 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.

| | As of December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| **Reserve Data[1]:** | | | |
| Estimated proved reserves: | | | |
| Oil (MMBbls) | 52.8 | 64.4 | 64.4 |
| Natural gas (Bcf) | 235.7 | 212.2 | 165.0 |
| Natural gas liquids (MMBbls) | 26.1 | 22.2 | 24.9 |
| Total estimated proved reserves (MMBoe)[2] | 118.2 | 121.9 | 116.8 |
| Percent oil and liquids | 67 % | 71 % | 76 % |
| Estimated proved developed reserves: | | | |
| Oil (MMBbls) | 24.3 | 25.4 | 23.7 |
| Natural gas (Bcf) | 123.2 | 105.8 | 79.6 |
| Natural gas liquids (MMBbls) | 14.3 | 11.6 | 11.7 |
| Total estimated proved developed reserves (MMBoe)[2] | 59.2 | 54.6 | 48.7 |
| Percent oil and liquids | 65 % | 68 % | 73 % |
| Estimated proved undeveloped reserves: | | | |
| Oil (MMBbls) | 28.5 | 39.0 | 40.6 |
| Natural gas (Bcf) | 112.5 | 106.4 | 85.4 |
| Natural gas liquids (MMBbls) | 11.8 | 10.6 | 13.2 |
| Total estimated proved undeveloped reserves (MMBoe)[2] | 59.0 | 67.3 | 68.1 |
| Percent oil and liquids | 68 % | 74 % | 79 % |

(1) Proved reserves were calculated using the preceding twelve month unweighted arithmetic average of the first-day-of-the-month prices, which were \$39.57 per Bbl WTI and \$1.99 per MMBtu HH, \$55.85 per Bbl WTI and \$2.58 per MMBtu HH, and \$65.56 per Bbl WTI and \$3.10 per MMBtu HH for the years ended December 31, 2020, 2019, and 2018, 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.

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, 2020 reserve report are included in our development plan and are scheduled to be drilled within five years from the year they were initially recorded. The Company's management evaluated the proved undeveloped drilling plan using the most recently supported type curves, NYMEX strip prices, the liquidation model for general and administrative costs, updated capital expenditures and lease operating costs to match revised bids and actuals from year-end. The reserve report factored in a completion rig working through our DUC inventory starting in 2021 and increasing to a one-and-a-half rig full drilling program starting in 2022, which results in all PUDs being on production within the allotted five-year window. Generally, the Company books proved undeveloped locations within one development spacing area from developed producing locations. For the instances where a proved undeveloped location is beyond one spacing area from a developed producing location, the Company utilized reliable geologic and engineering technology inclusive of, but not limited to, pressure performance, geologic mapping, offset productivity, electric logs, seismic, and production data.

As of December 31, 2020, we had 216 gross (297.5 SRL equivalents) proved undeveloped locations compared to 274 gross (402.0 SRL equivalents) for the comparable period in 2019. Of the total gross proved undeveloped locations at December 31, 2020, approximately 85% and 15% are scheduled to be drilled at 8-12 wells per section and 14+ wells per section, respectively. Wells per section are estimated based on equivalent spacing between wells for a 640-acre section.

Total estimated proved reserves at December 31, 2020 decreased 3.7 MMBoe, or 3%, to 118.2 MMBoe when compared to December 31, 2019. A summary of the Company's changes in quantities of proved reserves for the year ended December 31, 2020 is as follows:

| | Net Reserves (MBoe) |
|---|---|
| Beginning of year | 121,941 |
| Extensions and discoveries | 18,007 |
| Production | (9,239) |
| Sales of minerals in place | — |
| Removed from capital program | (22,908) |
| Purchases of minerals in place | 2,910 |
| Revisions to previous estimates | 7,481 |
| End of year | 118,192 |

The 18.0 MMBoe in PUD promotions was the result of converting 76 horizontal locations in the Niobrara formation in the Wattenberg Field to proved reserves during 2020 due to the 2021-2025 drilling program. The 22.9 MMBoe of PUD demotions is due to those locations being removed from the five-year drilling program. The positive revision to previous estimates of 7.5 MMBoe is the result of adding 12.3 MMBoe of engineering revisions offset by a pricing revision of 4.8 MMBoe resulting from a decrease in average commodity price from $55.85 per Bbl WTI and $2.58 per MMBtu HH for the year ended December 31, 2019 to $39.57 per Bbl WTI and $1.99 per MMBtu HH for the year ended December 31, 2020.

*Reconciliation of Proved Reserves 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. 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. Neither our PV-10 measure nor the Standardized Measure purports to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to Standardized Measure at December 31, 2020, 2019, and 2018 (in millions):

| | December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| PV-10 | $ 437.1 | $ 858.1 | $ 955.0 |
| Present value of future income taxes discounted at 10%[(1)] | — | — | — |
| Standardized Measure | $ 437.1 | $ 858.1 | $ 955.0 |

(1) The tax basis of our oil and gas properties as of December 31, 2020, 2019, and 2018 provides more tax deduction than income generated from our oil and gas properties when the reserve estimates were prepared using $39.57 per Bbl WTI and $1.99 per MMBtu HH, $55.85 per Bbl WTI and $2.58 per MMBtu HH, and $65.56 per Bbl WTI and $3.10 per MMBtu HH, respectively.

*Proved Undeveloped Reserves*

| | Net Reserves (MBoe) As of December 31, 2020 |
|---|---|
| Beginning of year | 67,338 |
| Converted to proved developed | (8,023) |
| Additions from capital program | 18,007 |
| Removed from capital program | (22,908) |
| Acquisitions, net | 1,834 |
| Revisions | 2,772 |
| End of year | 59,020 |

As of December 31, 2020, our proved undeveloped reserves were 59,020 MBoe, all of which are scheduled to be drilled within five years from the year they were initially recorded. During 2020, the Company converted 12% of its proved undeveloped reserves, which is comprised of 26 gross wells representing net reserves of 8,023 MBoe, at a cost of $42.3 million. The net increase of 18,007 MBoe in PUD additions is the result of adding 48 SRL and 28 XRL PUD locations in the areas that are captured in our five-year drilling program. The net decrease of 22,908 MBoe in PUD demotions is the result of removing 117 PUD locations as they were no longer part of our five-year drilling program. The acquisition of 1,834 MBoe in net PUD volumes is the result of adding 9 SRL PUD locations to be captured in our five-year drilling program.

*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 are engaged by and have direct access to the Reserves Committee. The reserves estimates shown herein have been independently prepared by Ryder Scott for the year ended December 31, 2020 and by NSAI for the years ended December 31, 2019 and 2018. These reserve estimates are reviewed by our in-house petroleum engineer who oversees and controls preparation of the reserve report data by working with our third-party independent reserve engineers to ensure the integrity, accuracy, and timeliness of data furnished for their evaluation process. The Company's technical person who was primarily responsible for overseeing the preparation of our reserve estimates was our Manager, Reserves Engineering, who has 16 years of experience in the oil and gas industry, including 4 years in her role at the Company. Her professional qualifications include a bachelor's degree in Chemical Engineering from the Colorado School of Mines.

*Independent Reserve Engineers*

The reserves estimates shown herein for December 31, 2020 have been independently evaluated by Ryder Scott, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Ryder Scott was founded in 1937 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-1580. Within Ryder Scott, the technical person primarily responsible for preparing the estimates set forth in the Ryder Scott reserves report incorporated herein is Scott Wilson. Scott Wilson, a Licensed Professional Engineer in the State of Colorado (No. 36112), has been practicing consulting petroleum engineering at Ryder Scott since 2000 and has over 35 years of industry experience. He graduated from Colorado School of Mines in 1983 with a Bachelor of Science in Petroleum Engineering and from the University of Colorado in 1985 with a Master's of Business Administration. The responsible party meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The reserves estimates shown herein for December 31, 2019 and 2018 were independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein were Mr. Benjamin W. Johnson and Mr. John G. Hattner. Mr. Johnson, a Licensed Professional Engineer in the State of Texas (No. 124738), has been practicing consulting petroleum engineering at NSAI since 2007 and has over 2 years of prior industry experience. He graduated from Texas Tech University in 2005 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner, a Licensed Professional Geoscientist in the State of Texas, Geophysics (No. 559), has been practicing consulting petroleum geoscience at NSAI since 1991, and has over 11 years of prior industry experience. He graduated from the 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**

Oil and gas prices fluctuated significantly during 2020. Oil prices are impacted by production levels, crude oil inventories, real or perceived geopolitical risks in oil producing regions, the relative strength of the U.S. dollar, weather, and global demand. During periods of favorable pricing, we expect increased industry activity, which could moderate the magnitude of price increases throughout the year.

*Sensitivity Analysis*

If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 2% and our PV-10 value as of December 31, 2020 would decrease by approximately 27% or $117.6 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 1% and our PV-10 value as of December 31, 2020 would increase by approximately 27% or $119.3 million.

*Production*

The following table sets forth information regarding oil, natural gas, and natural gas liquids 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*.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| **Oil:** | | | |
| Total Production (MBbls) | 5,019.4 | 5,135.9 | 3,840.8 |
| Wattenberg Field | 5,019.4 | 5,135.9 | 3,500.2 |
| Dorcheat Macedonia Field | — | — | 340.6 |
| Average sales price (per Bbl), including derivatives(3) | $ 44.41 | $ 52.12 | $ 54.77 |
| Average sales price (per Bbl), excluding derivatives(3) | $ 34.42 | $ 51.89 | $ 59.38 |
| **Natural Gas:** | | | |
| Total Production (MMcf) | 14,165.7 | 11,966.8 | 8,591.2 |
| Wattenberg Field | 14,165.7 | 11,966.8 | 7,408.3 |
| Dorcheat Macedonia Field | — | — | 1,182.8 |
| Average sales price (per Mcf), including derivatives(4) | $ 1.40 | $ 2.10 | $ 2.39 |
| Average sales price (per Mcf), excluding derivatives(4) | $ 1.45 | $ 2.06 | $ 2.45 |
| **Natural Gas Liquids:** | | | |
| Total Production (MBbls) | 1,858.2 | 1,431.1 | 1,141.2 |
| Wattenberg Field | 1,858.2 | 1,431.1 | 1,048.3 |
| Dorcheat Macedonia Field | — | — | 92.8 |
| Average sales price (per Bbl), including derivatives | $ 10.39 | $ 11.22 | $ 22.46 |
| Average sales price (per Bbl), excluding derivatives | $ 10.39 | $ 11.22 | $ 22.46 |
| **Oil Equivalents:** | | | |
| Total Production (MBoe) | 9,238.6 | 8,561.5 | 6,413.8 |
| Wattenberg Field | 9,238.6 | 8,561.5 | 5,783.2 |
| Dorcheat Macedonia Field | — | — | 630.6 |
| Average Daily Production (Boe/d) | 25,242 | 23,456 | 17,572 |
| Wattenberg Field | 25,242 | 23,456 | 15,844 |
| Dorcheat Macedonia Field | — | — | 1,728 |
| **Average Production Costs (per Boe)(1)(2)** | $ 4.00 | $ 4.35 | $ 7.11 |

(1) Excludes ad valorem and severance taxes.

(2) Represents lease operating expense and gas plant and midstream operating expense per Boe using total production volumes. Total production volumes exclude volumes from our percentage-of-proceeds contracts in our Mid-Continent region of 65.0 MBoe for the year ended December 31, 2018. The Mid-Continent region assets were sold August 6, 2018, and therefore, no sales volumes were associated with the Mid-Continent region during the years ended December 31, 2020 and 2019.

(3) Crude oil sales excludes $1.7 million, $2.4 million, and $0.6 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2020, 2019, and 2018, respectively.

(4) Natural gas sales excludes $3.7 million, $3.7 million, and $1.3 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2020, 2019, and 2018, respectively.

**Customers**

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 product.

**Delivery Commitments**

The Company is party to a purchase agreement to deliver fixed determinable quantities of crude oil to NGL Crude. The NGL Crude agreement includes defined volume commitments over a term ending in 2023. Under the terms of the NGL Crude agreement, the Company is required to make periodic deficiency payments for any shortfalls in delivering minimum gross volume commitments, which are set in six-month periods. The minimum gross volume commitment will increase approximately 3% each year for the remainder of the contract, to a maximum of approximately 16,000 gross barrels per day. The aggregate financial commitment fee over the remaining term is $49.7 million as of December 31, 2020. Please refer to *Part II, Item 8, Note 7 - Commitments and Contingencies* for additional discussion.

**Productive Wells**

The following table sets forth the number of productive oil and natural gas wells in which we owned a working interest at December 31, 2020.

| | Oil | | Natural Gas(1) | | Total | | Operated | |
|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Rocky Mountain | 758 | 608.0 | — | — | 758 | 608.0 | 633 | 579.3 |

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

**Acreage**

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2020, along with the PV-10 value. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary.

| | Developed Acres | | Undeveloped Acres | | Total Acres | | PV-10 |
|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | (in millions) |
| Rocky Mountain | 81,460 | 61,223 | 5,632 | 3,705 | 87,092 | 64,928 | $ 437.1 |

**Undeveloped acreage**

We critically review and consider at-risk leasehold with attention to our ability either to convert term leasehold to held-by-production status or obtain term extensions. Decisions to let leasehold expire generally relate to areas outside of our core area of development or when the expirations do not pose material impacts to development plans or reserves.

The following table sets forth the number of net undeveloped acres as of December 31, 2020 that will expire over the next three years unless production is established within the spacing units covering the acreage or the applicable leases are extended prior to the expiration dates:

| | Expiring 2021 | | Expiring 2022 | | Expiring 2023 | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Rocky Mountain | 3,843 | 1,859 | 1,347 | 1,356 | 162 | 297 |

**Drilling Activity**

The following table sets forth the exploratory and development wells completed (operated and non-operated) during the years ended December 31, 2020, 2019, and 2018.

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | 2019 | | 2018 | |
| | Gross | Net | Gross | Net | Gross | Net |
| **Exploratory** | | | | | | |
| Productive Wells | — | — | — | — | — | — |
| Dry Wells | — | — | — | — | — | — |
| Total Exploratory | — | — | — | — | — | — |
| **Development** | | | | | | |
| Productive Wells | 9 | 8.5 | 45 | 34.1 | 56 | 43.8 |
| Dry Wells | — | — | — | — | — | — |
| Total Development | 9 | 8.5 | 45 | 34.1 | 56 | 43.8 |
| **Total** | 9 | 8.5 | 45 | 34.1 | 56 | 43.8 |

The following table describes the present operated drilling activities as of December 31, 2020.

| | As of December 31, 2020 | |
|---|---|---|
| | Gross | Net |
| Exploratory | — | — |
| Development | 47 | 37.0 |
| Total | 47 | 37.0 |

## Derivative Activity

In addition to supply and demand, oil and gas prices are affected by seasonal, economic, local, and geo-political factors that we can neither control nor predict. We attempt to mitigate a portion of our exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows through the use of derivative contracts. As of December 31, 2020, the Company had entered into the following commodity derivative contracts:

| | Crude Oil (NYMEX WTI) | | Natural Gas (NYMEX Henry Hub) | | Natural Gas (CIG Basis) | | Natural Gas (CIG) | |
|---|---|---|---|---|---|---|---|---|
| | Bbls/day | Weighted Avg. Price per Bbl | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu |
| **1Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $43.67/$53.58 | 30,000 | $2.25/$2.57 | — | — | — | — |
| Swap | 5,000 | $54.48 | — | — | 20,000 | $0.43 | — | — |
| **2Q21** | | | | | | | | |
| Cashless Collar | 2,500 | $34.40/$49.82 | 20,000 | $2.25/$2.52 | — | — | — | — |
| Swap | 4,000 | $54.13 | — | — | 20,000 | $0.43 | — | — |
| **3Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $30.00/$50.62 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 2,500 | $54.45 | — | — | 20,000 | $0.43 | — | — |
| **4Q21** | | | | | | | | |
| Cashless Collar | 4,000 | $30.63/$50.34 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 1,000 | $55.20 | — | — | 20,000 | $0.43 | — | — |
| **1Q22** | | | | | | | | |
| Cashless Collar | 3,500 | $31.43/$51.00 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **2Q22** | | | | | | | | |
| Cashless Collar | 2,000 | $32.50/$54.85 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **3Q22** | | | | | | | | |
| Cashless Collar | 1,000 | $35.00/$54.88 | — | — | — | — | — | — |
| **4Q22** | | | | | | | | |
| Cashless Collar | 500 | $35.00/$55.00 | — | — | — | — | — | — |

As of the filing date of this report, the Company had entered into the following commodity derivative contracts:

| | Crude Oil (NYMEX WTI) | | Natural Gas (NYMEX Henry Hub) | | Natural Gas (CIG Basis) | | Natural Gas (CIG) | |
|---|---|---|---|---|---|---|---|---|
| | Bbls/day | Weighted Avg. Price per Bbl | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu |
| **1Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $43.67/$53.58 | 30,000 | $2.25/$2.57 | — | — | — | — |
| Swap | 5,000 | $54.48 | — | — | 20,000 | $0.43 | — | — |
| **2Q21** | | | | | | | | |
| Cashless Collar | 2,500 | $34.40/$49.82 | 20,000 | $2.25/$2.52 | — | — | — | — |
| Swap | 4,000 | $54.13 | — | — | 20,000 | $0.43 | — | — |
| **3Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $30.00/$50.62 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 2,500 | $54.45 | — | — | 20,000 | $0.43 | — | — |
| **4Q21** | | | | | | | | |
| Cashless Collar | 4,000 | $30.63/$50.34 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 1,000 | $55.20 | — | — | 20,000 | $0.43 | — | — |
| **1Q22** | | | | | | | | |
| Cashless Collar | 4,000 | $31.88/$51.83 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **2Q22** | | | | | | | | |
| Cashless Collar | 2,500 | $33.00/$55.41 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **3Q22** | | | | | | | | |
| Cashless Collar | 1,000 | $35.00/$54.88 | — | — | — | — | — | — |
| **4Q22** | | | | | | | | |
| Cashless Collar | 500 | $35.00/$55.00 | — | — | — | — | — | — |

**Title to Properties**

Our properties are subject to customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes, other industry-related constraints, and certain other 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 all of our producing properties. We undergo a thorough title review process upon receipt of title opinions prepared by outside legal counsel before we commence drilling operations. Although title to our properties is subject to complex interpretation of multiple conveyances, deeds, reservations, and other instruments that serve to affect mineral title, we believe that none of these risks will materially detract from the value of our properties or from our interest therein or otherwise 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 often 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. 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 and potential impacts of these risks are difficult to accurately predict.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 67% of our estimated proved reserves as of December 31, 2020 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2020, the daily NYMEX WTI oil spot price ranged from a high of $63.27 per Bbl to a low of negative $36.98 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $3.14 per MMBtu to a low of $1.33 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 customary, or because premium costs are considered cost-prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations, or cash flows.

**Regulation of the Oil and Natural Gas Industry**

Our operations are substantially affected by federal, state, and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes, and numerous other laws and regulations. The jurisdiction in which we own and operate properties or assets for oil and natural gas production has statutory provisions regulating the exploration for and production of oil and natural gas, including, among other things, 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 production and operation of wells and other facilities, 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 proper abandonment of wells and pipelines. 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 and the suspension or cessation of operations. 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. Because such laws and regulations are frequently revised and amended through various legislative actions and rulemakings, it is difficult to predict the future costs or impact of compliance. Additional rulemakings that affect the oil and natural gas industry are regularly considered at the federal, state, and various local government levels, including statutorily and through powers granted to various agencies that regulate our industry, and various court actions. We cannot predict when or whether any such rulemakings may become effective or if the outcomes will negatively affect our operations.

We believe 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, it is difficult to estimate the potential impact on our business from regulations adopted by the Colorado Oil and Gas Conservation Commission ("COGCC") in November 2020, which impose a number of new and amended environmental requirements on our operations. These requirements could make it more difficult and costly to develop new oil and natural gas wells and to continue to produce existing wells, increase our costs of compliance and doing business, and delay or prevent development in certain areas or under certain conditions. The COGCC is still in the process of issuing guidance and direction regarding the new requirements, and we cannot assure that these requirements as implemented will not have a material and adverse impact on our financial position, cashflows, or results of operations. In addition, the current regulatory requirements may change, currently unforeseen incidents may occur, or past noncompliance with laws or regulations may be discovered, any of which could likewise have a material adverse effect on our financial position, cashflows, or results of operations.

***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, among other things, permits for drilling operations, drilling bonds, and reports concerning operations. Colorado, the state in which we own and operate all of our properties, has 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 and associated facilities. These regulations effectively identify well densities by geologic formation and the appropriate 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, Colorado 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 one U.S. state, Colorado. This state regulates 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. Colorado laws also govern a number of environmental matters, including setbacks from buildings and schools, consideration of alternative locations for new wells, the handling and disposal of waste materials, prevention of venting and flaring, mitigation of noise, lighting, visual, odor, and dust impacts, air pollutant emissions permitting, protection of certain wildlife habitat, and evaluation of cumulative impacts.

***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 materially different from how it affects operations of our competitors who are similarly situated.

***Regulation of transportation and sales of natural gas***

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

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

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

The Domenici Barton Energy Policy Act of 2005 ("EP Act of 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful, 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, (1) 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 the state in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is materially different from how it affects operations of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

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

***Regulation of derivatives***

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.

**Environmental, Health and Safety Regulation**

Our natural gas and oil exploration and production operations are subject to numerous stringent federal, state, and local laws and regulations governing safety and health, the discharge of hazardous materials into the environment, or otherwise relating to protection of the environment or natural resources, noncompliance with which can result in substantial administrative, civil, and criminal penalties and other sanctions, including suspension or cessation of operations. These laws and regulations may, among other things, require the acquisition of permits and other approvals before drilling or other regulated activity commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment; require the assessment and mitigation of potential surface impacts; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities that have certain impacts or that occur in certain areas; require some form of investigation or 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, public health, and natural resource protection and impose substantial liabilities or curtail operations for unpermitted pollutant emissions or failure to comply with regulatory filing obligations. Cumulatively, these laws and regulations may impact our rate of production.

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

***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 and operation 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 expenditures for air pollution control equipment or other air emissions-related issues.

In May 2016, the U.S. Environmental Protection Agency (the "EPA") issued additional New Source Performance Standards ("NSPS") rules, known as Subpart OOOOa, focused on achieving additional methane and volatile organic compound reductions from oil and natural gas operations. Among other things, these revisions imposed new requirements for leak detection and repair, control requirements for oil well completions, and additional control requirements for gathering, boosting, and compressor stations. On September 14, 2020, EPA finalized the Review Rule rescinding prior source category determinations and parts of the 2016 rules regulating methane emissions from the oil and gas industry. Separately, on September 14, 2020, EPA finalized the Reconsideration Rule that made policy and technical amendments to the NSPS rules that were raised in administrative petitions that include proposed changes to, among other things, the frequency for monitoring fugitive emissions at well sites and compressor stations. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the Reconsideration Rule by September 2021. Both Rules are subject to ongoing litigation, and therefore, future obligations continue to remain uncertain under the Clean Air Act.

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 both existing and new or modified oil and gas facilities in Colorado. The regulations include new emissions control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in Colorado. For example, the 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. In December 2019, the AQCC adopted new and revised air quality regulations that extend the controls adopted in 2014 to many lower producing and emitting facilities statewide, and add storage tank loadout controls to those requirements, among other changes. The new rules also increase the frequency of LDAR monitoring to semi-annual for lower producing facilities previously subject to a one-time monitoring requirement, as well as require monthly LDAR monitoring for facilities within 1,000 ft. of occupied areas, and impose a new emission inventory and reporting of greenhouse gases ("GHGs"), among other requirements. Some of these new requirements became effective as early as January 30, 2020, with others requiring compliance by May 1, 2020, or May 1, 2021. Colorado's Air Quality Control Commission also revised rules specific to the oil and gas sector in September 2020, and again in December 2020. The September 2020 rules revisions included emission control requirements for natural gas fired engines typically in compression service, for pre-production tanks used in flowback, and also established a preproduction air monitoring plan requirement for operators for the first time. The December 2020 regulatory changes included revisions to leak detection requirements within 1,000 ft. of occupied areas, and proposed certain requirements for the pneumatic devices used in oil and gas production at new and modified facilities, but the latter revisions were not acted upon and were made the subject of a separate hearing which will be held in February 2021.

In October 2015, EPA finalized its rule lowering the existing 75 part per billion ("ppb") national ambient air quality standard (" 2008 NAAQS") for ozone under the CAA to 70 ppb ("2015 NAAQS"). Also in 2019, the state of Colorado's Denver Metro and North Front Range ("DM/NFR") air quality control region received a bump-up in its existing non-attainment status for the 2008 NAAQS from "moderate" to "serious." Oil and natural gas operations in "serious" ozone non-attainment areas, including in the DM/NFR area, are subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements for new and modified facilities, and increased permitting delays and costs. Additionally, The DM/NFR's non-attainment boundary for the 2015 NAAQS was successfully challenged by environmental groups and local governments seeking to expand the boundary to include all of northern Weld County in the case of Clean Wisconsin v. EPA, No. 18-1203, in which the D.C. Circuit remanded the boundary determination to EPA for further support or re-designation. A response to the court's remand by EPA is expected later in 2021. Finally, a "severe" non-attainment status designation for the DM/NFR by EPA appears likely in early 2022 due to violations at area monitors during the 2020 ozone season. A "severe" classification would trigger significant additional obligations under the CAA and state statute and will result in new and more stringent air quality control requirements applicable to our operations and significant operating costs and delays in obtaining necessary permits for new and modified production facilities.

In May 2016, the EPA also finalized a rule regarding source determination, including defining the term "adjacent" under the CAA, which affects how major sources are defined, particularly regarding criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed major sources, thereby triggering more stringent air permitting requirements. These EPA rulemakings will have nominal effect on our operations, because the rule clarified our existing presumption on "adjacent" and presents no conflict with the state of Colorado definitions.

The EPA also published Control Technique Guidelines ("CTGs") in October 2016 aimed at providing states with guidance and setting a presumptive floor for Reasonably Achievable Control Technology ("RACT") for the oil and gas industry in areas of ozone non-attainment, including the DM/NFR area. In November 2017, as required following issuance of the CTGs, the Colorado Air Quality Control Commission AQCC adopted additional RACT and other air quality regulations that increased emissions control, monitoring, recordkeeping, and reporting requirements on oil and gas operators in the DM/NFR area, and to some extent state-wide.

In November 2020, the COGCC adopted new regulations that generally prohibit the venting or flaring of natural gas during drilling, completion, and production operations, with limited exceptions. Among other things, these regulations require that operators proposing new oil and gas wells either commit to connecting to a gathering system when production commences or submit a gas capture plan.

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.

***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, the disclosure of the chemicals used in fracturing, or other matters. Colorado, for example, requires operators to reduce hydrocarbon emissions associated with hydraulic fracturing, compile and report additional information regarding wellbore integrity, publicly disclose the chemical ingredients used in hydraulic fracturing, maintain minimum distance between occupied structures and oil and gas wells, undertake additional mitigation for nearby residents, and implement additional groundwater testing. 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 to 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.

Federal agencies have periodically considered 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. As noted above, in June 2016, EPA finalized regulations that address discharges of wastewater pollutants from onshore unconventional extraction facilities to publicly-owned treatment works, and after a legal challenge by environmental groups, in July 2019, the EPA declined to revise the rules. The EPA also published a study of the impact of hydraulic fracturing on drinking water resources in December 2016, which concluded that drinking water resources can be affected by hydraulic fracturing under specific circumstances. The results of this study could result in additional regulations, which could lead to operational burdens similar to those described above. The United States Department of the Interior also finalized a rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity, and handling of flowback water; however, on December 29, 2017, the Bureau of Land Management ("BLM") issued a rescission of the hydraulic fracturing rule. This rescission and the rule as promulgated are subject to ongoing litigation. Additionally, in early 2016, the BLM proposed rules related to further controlling the venting and flaring of natural gas on BLM land. Following the adoption of these rules in late 2016, a group led by the states of Wyoming and Montana, later joined by North Dakota and Texas, challenged the rules in the United States District Court for the District of Wyoming. On September 28, 2018, the BLM published a final rule that revised the 2016 rules. The new rule, among other things, rescinded the 2016 rule requirements related to waste-minimization plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels, and leak detection and repair. The new rule also revised provisions related to venting and flaring. Environmental groups and the states of California and New Mexico filed challenges to the 2018 rule in the United States District Court for the Northern District of California. In July of 2020, the California court vacated the 2018 revisions but stayed its vacatur of the rules for 90 days. On October 8, 2020, before the 90-day stay of the California court's vacatur expired, the Wyoming court struck down the 2016 rules on the grounds that the BLM exceeded its statutory authority by adopting rules to protect air quality, a role delegated to the EPA. The federal government appealed the decision from California and the citizen groups, New Mexico, and California appealed the decision from Wyoming. Future litigation therefore creates some uncertainty as to how BLM's regulation of venting and flaring will impact our business.

Apart from these ongoing federal and state initiatives, some state and local governments have adopted their own new requirements on hydraulic fracturing and other oil and gas operations. Voters in Colorado have proposed or advanced initiatives restricting or banning oil and gas development in Colorado, but these initiatives have failed to date. 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. In addition, in light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, certain regulators have adopted or are considering additional requirements related to seismic safety for hydraulic fracturing activities or the underground injection of fluid wastes. For example, the regulations that the COGCC adopted in November 2020 impose various new requirements on the underground injection of fluid wastes to further seismic safety and protect the environment. Any regulation that restricts our ability to dispose of produced waters or increases the cost of doing business could have a material adverse effect on our business.

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. We cannot assure 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 the Rocky Mountain region.

Typical hydraulic fracturing treatments are made up of water, chemical additives, and sand. We utilize major hydraulic fracturing service companies who track and report additive chemicals that are used in fracturing as required by the appropriate government agencies, including FracFocus, the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Each of the service companies we use fracture stimulate a multitude of wells for the industry each year.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. 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.

***Other State Laws***

Our properties located in Colorado are subject to the authority of the COGCC, as well as other state agencies. The COGCC finalized new flowline rules in February 2018. The new rules include: increased registration requirements, flowline design requirements, integrity management requirements, and leak detection programs, and requirements for abandoned flowlines. In November 2019, the COGCC further amended its flowline rules to impose additional requirements regarding flowline mapping, operational status, certification, and abandonment, among other things. 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, spacing of wells and pooling of mineral interests, and an increase in potential sanctions for COGCC rule violations. In June 2020, the COGCC adopted new regulations to further enhance wellbore integrity and improve safety and environmental protection during hydraulic fracturing and in November 2020 also took action to revise its 800 Series Rules for Class II underground injection control (UIC) wells as part of its historic "Mission Change" rulemaking. 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 to operate 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.

In 2016, the Colorado Supreme Court ruled that the cities of Fort Collins and Longmont do not have authority to ban oil and gas operations within their jurisdictional limits. Although we do not own or lease minerals or operate within any of these municipal areas, the Colorado Supreme Court decision has bearing on our ability to continue to operate in Colorado. Further, Weld County completed implementation of a revised local government permitting process for land use approval, and Boulder County substantially revised its oil and gas regulations. We do not expect that these local government regulations will have any material impact on our operations.

In April 2019, new legislation became effective in Colorado, which substantially changes the state's regulation of oil and gas exploration and production activities. The new law changes the COGCC's mission from "fostering" responsible and balanced development to "regulating" development to protect public health and the environment. The required composition of the COGCC was changed to remove two seats for industry experts and add experts on wildlife/environmental protection and public health, and the Commissioners changed from volunteer to full-time positions. The state's statutory pooling provisions were also changed by the new law to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required.

Among the most significant changes under the legislation was the provision of local government control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments may now inspect oil and gas operations and impose fines for leaks, spills, and emissions.

The legislation mandates COGCC rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned, or shut-in, financial assurance, wellbore integrity, and application fees. The COGCC completed rulemaking on flowlines and wells that are inactive, temporarily abandoned, or shut-in in November 2019, completed rulemaking on wellbore integrity in June 2020, and completed a major rulemaking on the COGCC's "mission change" in November 2020. The mission change rulemaking was intended to align the regulations to the COGCC's new mission. It addressed a wide range of topics including facility siting, cumulative impacts, development approvals, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection. The mission change rules took effect on January 15, 2021, and they apply to permit applications pending on or submitted after that date and generally to operations occurring on or after that date. The agency is currently in the process of issuing written guidance on many of the issues addressed to provide direction on regulatory interpretation and compliance. The COGCC is expected to undertake rulemaking on financial assurance and application fees during 2021.

Additionally, the new legislation requires the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds and nitrogen oxides associated with certain oil and gas facilities. The AQCC adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, and expanded storage tank control requirements and loadout control requirements statewide in December 2019. The AQCC may also adopt requirements for installation of continuous emission monitoring equipment at certain oil and gas facilities, and reduced emissions from pneumatic devices in future rulemaking scheduled for 2021. The legislation also grants the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling and completion.

***Hazardous substances and waste handling***

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these potentially responsible parties 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 or contain CERCLA hazardous substances but we are not aware of any liabilities for which we may be held responsible that would materially or adversely affect us.

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes, and distinguishes between hazardous and non-hazardous or solid wastes. With the approval of the EPA, the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent hazardous waste requirements, while all states regulate solid waste. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development, and production of natural gas and oil are currently regulated under RCRA's non-hazardous waste provisions and state solid waste laws. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain oil and natural gas exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent and costly handling, disposal, and clean-up requirements. For example, in May 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia that seeks to compel the EPA to review and, if necessary, revise its regulations regarding existing exemptions for exploration and production related wastes. On December 28, 2016, the EPA entered into a consent decree with those environmental groups to settle the lawsuit, which required the EPA by March 15, 2019 to either propose new regulations regarding exploration and production related wastes or sign a determination that revision of such regulations is not necessary. Pursuant to the consent decree, EPA determined in April 2019 that revision of the regulations is unnecessary. EPA indicated that it will continue to work with states and other organizations to identify areas for continued improvement and to address emerging issues to ensure that exploration, development, and production wastes continue to be managed in a manner that protects human health and the environment. Environmental groups, however, expressed dissatisfaction with EPA's decision and will likely continue to press the issue at the federal and state levels, especially under the new Biden Administration.

In 2018, the Colorado State legislature passed Senate Bill 245 that gave the Colorado Department of Public Health & Environment ("CDPHE") the authority to promulgate rules for the safe management of Technologically Enhanced Naturally Occurring Radioactive Material ("TENORM"). TENORM is naturally occurring radioactive material whose radionuclide concentrations are increased through human activity, such as through generation of water treatment residuals, scales and sediments from oil and gas production, and other processes. The bill requires the Department to review TENORM residual management and regulatory limits from other states as well as prepare a report that considers background radiation levels in the state, waste stream identification and quantification, use and disposal practices, current engineering practices, appropriate test methods, economic impacts, and data gaps. This work was completed by CDPHE in 2019. During 2020, CDPHE promulgated new rules governing TENORM waste, which were adopted in November 2020 and became effective January 14, 2021, but are not enforceable until July 14, 2022, to provide operators time to come into compliance. During drilling, completion, and production, numerous waste streams that may contain TENORM are created that are hauled for disposal at permitted disposal facilities. Depending on the final waste streams chosen for characterization and regulatory levels set for disposal, costs for characterization, storage, and disposal of waste could significantly increase.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore for and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, exploration and production fluids and gases 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 in January 2017, EPA issued a proposed rule to include natural gas processing facilities in the TRI program. EPA review of comments on this proposed rule is ongoing, but no further regulatory action has been taken by EPA to date.

***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 penalties, liability for natural resources damages, and significant business interruption. The U.S. Department of Transportation has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection, and management of our pipeline and storage facilities. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. The Pipeline Safety, Regulatory Certainty, and Job Creation Act was signed into law in early 2012. In addition, the Pipeline and Hazardous Materials Safety Administration ("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. In 2016, PHMSA increased its regulations to require crude oil sampling and reporting as an "offeror" (as defined under the PHMSA) and increased its civil penalty structure.
In Colorado, the Public Utilities Commission ("PUC") adopted amended Rules Regulating Pipeline Operators and Gas Pipeline Safety for intrastate pipelines on December 16, 2020. Following public and stakeholder comment, an Administrative Law Judge for the PUC issued a Recommended Decision on November 4, 2020, recommending that the PUC formally adopt proposed revisions. The scope of the rules includes all gas public utilities, all municipal or quasi-municipal corporations transporting natural gas or providing natural gas services, all operators of master meter systems, and all operators of pipelines transporting

gas in intrastate commerce including gas gathering system operators (certain provisions are tailored to the location and size of the gathering systems involved). The rules require all filed reports to be publicly available and all Notices of Proposed Violation, Notices of Action, pleadings and decisions to be filed publicly. The rules also provide a revised methodology for calculating civil penalties in an effort to provide clarity to both operators and the public.

***Climate change***

Based on EPA findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment, the EPA adopted regulations under the CAA that, among other things, established Prevention of Significant Deterioration ("PSD"), construction, and Title V operating permit reviews for GHG emissions from certain large stationary sources that are already major sources of emissions of regulated air pollutants. In a subsequent ruling, the U.S. Supreme Court upheld a portion of EPA's GHG stationary source program, but also invalidated a portion of it, holding that stationary sources already subject to the PSD or Title V program for non-GHG criteria pollutants remained subject to GHG BACT requirements, but that sources subject to the PSD or Title V program only for GHGs could not be forced to comply with EPA's GHG Best Available Control Technology ("BACT") requirements. Upon remand, the D.C. Circuit issued an amended judgment, which, among other things, vacated the PSD and Title V regulations under review in that case to the extent they require a stationary source to obtain a PSD or Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. In October 2016, EPA issued a proposed rule to further revise its PSD and Title V regulations applicable to GHGs in accordance with these court rulings, including a proposed de minimis level of GHG emissions below which BACT is not required. This rulemaking process was not finalized. If EPA promulgates new rules under the Biden Administration, it is possible that any regulatory or permitting obligation that limits emissions of GHGs could extend to smaller stationary sources and require us to incur costs to reduce and monitor emissions of GHGs associated with our operations, and may also adversely affect demand for the oil and natural gas that we produce.

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.

In August of 2015, the EPA finalized rules to further reduce GHG emissions, primarily from coal-fired power plants, under its Clean Power Plan ("CPP"). On March 28, 2017, President Trump signed an Executive Order directing the EPA to review the CPP regulations. Following the Executive Order, on April 4, 2017, the EPA announced that it was formally reviewing the CPP. On October 9, 2017, the EPA published a proposed rule to repeal the Clean Power Plan. On July 8, 2019, EPA finalized the Affordable Clean Energy ("ACE") rule, which established emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE replaced the CPP and provided states with new emission guidelines that informed their development of standards of performance to reduce carbon dioxide (CO2) emissions from existing coal-fired power plants. Long-pending legal challenges to the CPP rule filed by states, industry and environmental groups were dismissed as moot by the D.C. Circuit Court of Appeals on September 17, 2019, given the issuance of a final replacement ACE rule. On January 19, 2021, the D.C. Circuit struck down the ACE Rule and remanded it to the EPA; therefore, the regulation of GHG emissions is uncertain at this time.

Congress has, from time to time, considered but not yet passed legislation to reduce emissions of GHGs. In addition, 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.

Additional GHG regulation may also result from the December 2015 agreement that the United States reached during the December 2015 United Nations climate change conference in Paris, France (the "Paris Agreement"). Within the Paris Agreement, the United States agreed to reduce its GHG emissions by 26-28% by the year 2025 as compared with 2005 levels, and provide periodic updates on its progress. On June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement. Although former President Trump's announced withdrawal finally took effect on November 4, 2020, among President Biden's first actions was the issuance of an executive order and the provision of 30-day advance notice to the United Nations of the United States' return to the Paris Agreement.

On May 30, 2019, Colorado also passed GHG inventory legislation and climate action legislation. House Bill 19-1261 concerns the reduction of greenhouse gas pollution and established statewide greenhouse gas pollution reduction goals. Senate Bill 19-096 concerns the collection of greenhouse gas emissions data to facilitate measures to cost-effectively meet the states GHG emissions reduction goals established in HB 19-1261. Regulations implementing the GHG inventory requirements of these statutes were promulgated by the Colorado Air Quality Control Commission in May of 2020 and became effective on July 15, 2020. Additionally, on September 30, 2020, the Colorado Energy Office and Colorado Department of Public Health and Environment released a draft Greenhouse Gas Pollution Reduction Roadmap for public comment, and finalized the document on January 14, 2021. The GHG Roadmap lays out a pathway to meet the state's climate action targets established in HB 19-1261.

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 our production operations and/or demand for the oil and natural gas we produce. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could also reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities.

***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 of the U.S., including spills and leaks of hydrocarbons and produced water. 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. 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. In June 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") adopted a new regulatory definition of "waters of the U.S." ("WOTUS"), which was repealed by the EPA on October 22, 2019, restoring the 1986 regulatory definition of "Waters of the United States," – step 1 of a two-step process. Then in January 2020, EPA and the Corps released the Navigable Waters Protection Rule ("NWPR") which updates the federal definition for a WOTUS – the second step in the two-step process to repeal and replace the 2015 rule – and published the final rule on April 21, 2020. The NWPR went into effect on June 22, 2020. Numerous environmental, agricultural and business groups and state governments have challenged the NWPR in various courts, and one such challenge in Colorado resulted in the grant of a stay of the rule in that state, where the 2015 rule remains in effect. At President Biden's direction, the EPA and the U.S. Army Corps of Engineers requested the litigation be stayed while the agencies review the NWPR.

***Endangered Species Act and Migratory Bird Treaty Act***

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. In August 2019, the U.S. Fish and Wildlife Service (the "FWS") and National Marine Fisheries Service issued three rules amending implementation of the ESA regulations revising, among other things, the process for listing species and designating critical habitat. A coalition of states and environmental groups have challenged the three rules and the litigation remains pending. In addition, on December 18, 2020, the FWS amended its regulations governing critical habitat designations. We anticipate the rule will be subject to litigation. A final rule amending how critical habitat and suitable habitat areas are designated was finalized by the U.S. Fish and Wildlife Service in 2016. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. On January 7, 2021, the Department of the Interior finalized a rule limiting application of the MBTA, however the Department of the Interior under President Biden delayed the effective date of the rule and opened a public comment period for further review. Future implementation of the rules implementing the ESA and the MBTA are uncertain. 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 ("OSHA"), and comparable state statutes, the purpose of which are to protect the health and safety of workers. In 2016, there were substantial revisions to the regulations under OSHA that may impact our operations. These changes include among other items: record keeping and reporting, revised crystalline silica standard (which requires the oil and gas industry to implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021), naming oil and gas as a high hazard industry, and requirements for a safety and health management system. In addition, OSHA'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, requires 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.

***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 federal actions having the potential to significantly impact the human environment. In the course of such evaluations, an agency will evaluate the potential direct, indirect, and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a detailed environmental impact statement 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. The vast majority of our exploration and production activities are not on federal lands. This environmental review process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects on federal lands. Authorizations under NEPA also are subject to protest, appeal, or litigation, which can delay or halt projects. On July 16, 2020, the Council on Environmental Quality ("CEQ") revised NEPA's implementing regulations to make the NEPA process more efficient, effective, and timely. The final rule requires federal agencies to develop procedures consistent with the new rule within one year of the rule's effective date. The new regulations are subject to ongoing litigation in several federal district courts and future implementation of the regulations is unclear.

***Oil Pollution Act***

The Oil Pollution Act of 1990 ("OPA") establishes strict liability for owners and operators of facilities that release 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.

**Human Capital**

As of December 31, 2020, the Company had 109 employees, of which 29 full-time employee equivalents were dedicated to our Rocky Mountain Infrastructure, LLC operations. The Company's diverse team of talented employees possess a vast array of skills including engineering, geology, research and development, midstream operations, production, logistics and administrative support, such as accounting, information technology, legal, human resources and finance. Certain of the Company's employees have highly specialized skills and subject-matter expertise in their respective fields, which helps enable the Company to deliver industry leading innovation and results.

The Company attracts and maintains talent by offering market rate competitive salaries for the locations in which it operates, and by engaging employees with rewarding opportunities to contribute to the success of the Company. The Company is committed to supporting and developing its employees through learning and development programs. These programs are designed to build and strengthen employees' skills, including leadership and professional competencies. Such efforts also include routine and consistent compliance training, covering a wide-range of relevant subjects. The Company has consistently re-invested in necessary resources to effectively staff and efficiently support its business.

Employee health and safety in the workplace is one of the Company's core values. Safety efforts are led by the Environmental, Health, and Safety & Regulatory Compliance ("EHS&RC") team and supported by individuals at the local site level. Hazards in the workplace are timely identified, and management actively tracks incidents so remedial actions may be implemented to improve workplace safety. The Company also provides an injury case management program that provides medical management services tailored to any injured employee to best meet their recovery needs. Additionally, all field employees attend training provided by the COGCC or by the EHS&RC department to proactively ensure compliance and adherence related to recently issued rules and regulations. In response to the COVID-19 pandemic, the Company has taken actions aligned with the World Health Organization and the Centers for Disease Control and Prevention to protect its workforce so they can more safely and effectively perform their work. In so doing, the Company has prioritized the initiation of comprehensive health and safety protocols, further ensuring strict adherence to responsive measures for mitigating the spread of COVID-19.

The Nominating and Corporate Governance Committee of the Board (the "Governance Committee") considers diversity as a criteria evaluated as part of the attributes and qualifications that a Board candidate possesses. The Governance Committee construes the notion of diversity broadly, considering differences in viewpoint, professional experience, education, skills and other individual qualities, in addition to race, gender, age, ethnicity and cultural backgrounds as elements that contribute to a diverse Board. In keeping with this diversity commitment, the most recent director appointed to the Board, who brings substantial experience in the form of executive leadership in the petroleum industry, furthered the Board's goal of enhancing diversity. The Company is committed to efforts to increase diversity and foster an inclusive work environment that supports the Company's workforce.

We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

**Offices**

As of December 31, 2020, we leased 63,783 square feet of office space in Denver, Colorado at 410 17th Street where our principal offices are located, and we leased 7,780 square feet near our operations in Weld County, Colorado, where we have a field office and storage facilities. We also own a field office in Evans, Colorado.

**Available Information**

We are required to file annual, quarterly, and current reports, proxy statements and other information with the SEC. Our filings with the SEC are 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 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.

**Summary of the Risk Factors We Face**:

- Further declines in oil and 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.
- Excess supply of oil and natural gas resulting from reduced demand caused by COVID-19 pandemic and effects of actions by oil and natural gas producing countries have resulted, and may continue to result, in transportation and storage constraints, and reductions of our planned production, and may cause shut-in of our wells.
- Terrorist attacks could have a material adverse effect on our business, financial condition, or results of operations.
- Our production is not fully hedged, and we are exposed to fluctuations in price of oil, natural gas, and NGLs and will be affected by continuing and prolonged declines in such prices. At the same time, our derivative activities could result in financial losses or could reduce our income.
- Extent to which COVID-19 pandemic impacts our business, results of operations, and financial condition will depend on future developments, which cannot be predicted.
- Our Credit Facility has restrictive covenants that could limit our growth and our ability to finance operations, fund capital needs, respond to changing conditions, and engage in other business activities. Further, borrowings under our Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.
- Our exploration, development, exploitation, and production 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 decline in our oil and natural gas reserves or anticipated production volumes.
- Drilling for and producing oil and natural gas are high-risk activities with many uncertainties.
- Our estimated proved reserves and ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate.
- Present value of future net revenues from our proved reserves will not necessarily be same as current market value of our estimated oil and natural gas reserves.
- 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 intend to pursue further development through horizontal drilling and completion. Horizontal development operations can be more operationally challenging and costly relative to our historic vertical drilling operations.
- We may be unable to make attractive acquisitions, and any inability to do so may disrupt our business and hinder our ability to grow.
- The HighPoint Acquisition is subject to number of regulatory approvals and conditions, which may delay the Acquisition, result in additional expenditures of money and resources or reduce anticipated benefits or result in termination of the Merger Agreement.
- The Merger Agreement subjects us to restrictions on our business activities prior to closing.
- We may not realize anticipated benefits from acquisitions, including HighPoint Acquisition.
- Concentration of our operations in one core area may increase our risk of production loss.
- As a Colorado-only oil and gas operator, we face disproportionate risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities.
- State law requiring that we own or control more than 45% of working or mineral interest in order to statutorily pool our applicable interest may make it much more difficult for us to develop such interests.

- We have limited control over activities on properties in which we own interest but we do not operate, which could reduce our production and revenues.
- Concentrated nature of RMI system may increase risk that we suffer lengthy interruptions in production.
- Development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Our undeveloped reserves may not be ultimately developed or produced.
- Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.
- Certain of our undeveloped leasehold acreage is subject to leases that will expire over next several years unless production is established.
- Unless we replace our oil and natural gas reserves, our reserves and production will decline.
- We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.
- We are subject to health, safety, and environmental laws and regulations that may expose us to significant costs and liabilities.
- Evolving environmental legislation or regulatory initiatives, including those related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.
- Climate change laws and regulations restricting emissions could result in increased operating costs and reduced demand for oil and natural gas, while physical effects of climate change could disrupt our production and cause us to incur significant costs.
- Negative shift in investor sentiment of oil and gas industry could have adverse effects on our ability to raise debt and equity capital and on our operations.
- We are exposed to credit risks of our hedging counterparties, third parties participating in our wells, and our customers.
- Current or proposed financial legislation and rulemaking could adversely affect on our ability to use derivative instruments.
- We may be involved in legal cases that may result in substantial liabilities.
- We may become subject to new taxes, and certain tax deductions and exemptions currently available with respect to oil and gas exploration and development may be eliminated or reduced.
- Transactions in connection with the HighPoint Acquisition could trigger limitation on utilization of our historic net operating loss carryforwards and will trigger limitation on utilization of HighPoint's historic net operating loss carryforwards.
- We are at risk of cyber security incidents that could result in information theft, data corruption, operational disruption, or financial loss.
- Market price for our common stock following the HighPoint Acquisition may be affected by factors different from those that historically have affected or currently affect our common stock.
- We do currently not intend to pay, and are subject to certain restrictions on our ability to pay, dividends on our common stock.
- We have experienced recent volatility in market price and trading volume of our common stock and may continue to do so in the future.
- Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals.
- Our certificate of incorporation designates Delaware Court of Chancery as sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain favorable judicial forum.

**Risks Related to Our Business**

***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 natural gas liquids ("NGLs"), heavily influences our revenue, profitability, cash flows, liquidity, 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 67% of our estimated proved reserves as of December 31, 2020 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 and has not regained previous highs. As a result, we experienced significant decreases in crude oil revenues and recorded unproved property asset impairment charges. A prolonged period of low market prices for oil, natural gas, and NGLs or further declines in the market prices for oil and natural gas, could result in capital expenditures being further reduced and will adversely affect our business, financial condition, and liquidity and our ability to meet obligations, targets, or financial commitments. During the year ended December 31, 2020, the daily NYMEX WTI oil spot price ranged from a high of $63.27 per Bbl to a low of negative $36.98 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $3.14 per MMBtu to a low of $1.33 per MMBtu. As of February 10, 2021, the daily NYMEX WTI oil spot price and NYMEX natural gas HH spot price was $58.68 per Bbl and $3.73 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;
- variability in subsurface reservoir characteristics, particularly in areas with immature development history;
- 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 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 reduction in our liquidity and 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;
- 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 Credit Facility (defined below) or limitations in our access to sources of capital, such as equity or debt;
- declines in our stock price;
- reduction in industry demand for crude oil;
- reduction in storage availability for crude oil;
- reduction in pipeline and processing industry demand and capacity for natural gas;
- reduction in the ability of our vendors, suppliers, and customers to continue operations due to the prevailing adverse market conditions; and
- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment.

***The excess supply of oil and natural gas resulting from the reduced demand caused by the COVID-19 pandemic and the effects of actions by, or disputes among or between, oil and natural gas producing countries has resulted, and may continue to result, in transportation and storage constraints, and reductions of our planned production, and may cause shut-in of our wells, which could adversely affect our business, financial condition, and results of operations.***

The worldwide outbreak of COVID-19, the uncertainty regarding the impact of COVID-19, and various governmental actions taken to mitigate the impact of COVID-19, have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production, followed by curtailment agreements among OPEC and other countries, including Russia, has increased uncertainty and volatility around global oil supply-demand dynamics and further increased the excess supply of oil and natural gas. To the extent that the outbreak of COVID-19 continues to negatively impact demand, and OPEC members and other oil exporting nations fail to implement production cuts or other actions that are sufficient to support and stabilize commodity prices, we expect there to be excess supply of oil and natural gas for a sustained period. This excess supply has, in turn, resulted, and may continue to result, in transportation and storage capacity constraints in the United States, including in the DJ Basin where we operate, which may continue for a sustained period. For example, the substantial number of outstanding futures contracts, in conjunction with the market's perception that crude oil storage in Cushing, Oklahoma was inadequate for May 2020 deliveries, caused NYMEX WTI futures prices to settle at negative $37.63 per Bbl on April 20, 2020, a dynamic that has not previously occurred.

If, in the future, our ability to sell our production is hindered because of transportation or storage constraints, we may be required to shut-in or curtail production or flare our natural gas. Further, any prolonged shut-in of our wells may result in decreased well productivity once we are able to resume operations, and any cessation of drilling and development of our acreage could result in the expiration, in whole or in part, of our leases. All of these impacts resulting from the confluence of the COVID-19 pandemic and the price war between Saudi Arabia and Russia may adversely affect our business, financial condition, and results of operations.

Due to the commodity price environment, we have postponed a significant portion of our developmental drilling. A sustained period of weakness in oil, natural gas, and NGLs prices, and the resultant effects of such prices on our drilling economics and ability to raise capital, will require us to reevaluate and further postpone or eliminate additional drilling. Such actions would likely result in the reduction of our PUDs and related PV-10 and a reduction in our ability to service our debt obligations. If we are required to further curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, if oil, natural gas and/or NGLs prices experience a sustained period of weakness, our future business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures may be materially and adversely affected.

***Terrorist attacks could have a material adverse effect on our business, financial condition, or results of operations.***

Terrorist attacks may significantly affect the energy industry, including our operations and those of our current and potential customers, as well as general economic conditions, consumer confidence and spending, and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Our insurance may not protect against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations.

***Our production is not fully hedged, and we are exposed to fluctuations in the price of oil, natural gas, and NGLs and will be affected by continuing and prolonged declines in such prices.***

Oil, natural gas, and NGL prices are volatile. We hedge a portion of our oil and natural gas production to reduce our exposure to adverse fluctuations in these prices. We have stated limitations as prescribed in our reserve-based revolving credit facility, as the borrower, with JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions as lenders (the "Credit Facility") as to the percentage of our production that can be hedged. The limitations range from 85% to 100% of our projected production from our proved developed properties and 65% to 85% of our projected production from our total proved properties, dependent on the duration of the hedge. Due to the Credit Facility's restrictions and/or management's decision to hedge less than 100% of our projected production, some of our future production will be sold at market prices, exposing us to fluctuations in the price of crude oil and natural gas. Currently, we have hedged approximately 6,200 Bbls per day in 2021, representing approximately 50% of our oil sales volume during the three months ended December 31, 2020, and our hedging for 2022 oil production is even more limited. We intend to continue to hedge our production, but we may not be able to do so at favorable prices. Accordingly, our revenues and cash flows are subject to increased volatility and may be subject to significant reduction in prices, which would have a material negative impact on our results of operations. 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.

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

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

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

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

In addition, these types of derivative arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements. Further, our Credit Facility provides for certain limitations to the extent of our hedging, which may expose us to unfavorable fluctuations in the prices of oil and natural gas.

***The extent to which the COVID-19 pandemic impacts our business, results of operations, and financial condition will depend on future developments, which cannot be predicted.***

The outbreak of COVID-19, which has been declared by the World Health Organization to be a pandemic, has spread across the globe and is impacting worldwide economic activity, including the global demand for oil and natural gas. Any pandemic or other public health epidemic, including COVID-19, poses the risk that we or our employees, vendors, suppliers, customers, and other business partners may be prevented from conducting business activities for an indefinite period of time due to the potential spread of the disease within these groups or due to restrictions that may be requested or mandated by governmental authorities, including quarantines of certain geographic areas, restrictions on travel, and other restrictions that prohibit employees from going to work. To date, the COVID-19 outbreak has surfaced in all regions around the world and has severely impacted the global economy, disrupted consumer spending and global supply chains, and created significant volatility and disruption of financial markets, all of which are expected to continue.

The COVID-19 pandemic has caused us to modify our business practices (including employee travel, employee work locations, and cancellation of physical participation in meetings, events, and conferences), and we may take further actions as may be required by government authorities or that we determine are in the best interests of our employees, vendors, suppliers, customers, and other business partners. There is no certainty that such measures will be sufficient to mitigate the risks posed by the virus or otherwise be satisfactory to government authorities.

The extent to which COVID-19 impacts our business, results of operations, and financial condition will depend on future developments, which are uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus or treat its impact, and how quickly and to what extent normal economic and operating conditions can resume. If COVID-19 continues to spread or the response to contain COVID-19 is unsuccessful, we could experience a material adverse effect on our business, financial condition, and results of operations. Even after the coronavirus outbreak has subsided, we may continue to experience materially adverse impacts to our business as a result of its global economic impact, including any recession that has occurred or may occur in the future.

***The Credit Facility has restrictive covenants that could limit our growth and our ability to finance our operations, fund capital needs, respond to changing conditions, and engage in other business activities that may be in our best interests.***

The Credit Facility contains restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio and a maximum leverage ratio. In addition, the Credit Facility contains covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness;
- issue preferred stock;
- sell or transfer assets;
- pay dividends on, redeem, or repurchase capital stock;
- repurchase or redeem subordinated debt;
- make certain acquisitions and investments;
- create or incur liens;
- engage in transactions with affiliates;
- enter into agreements that restrict distributions or other payments from restricted subsidiaries to us;
- consolidate, merge, or transfer all or substantially all of our assets; and
- engage in certain other 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 may 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 the date of this Annual Report on Form 10-K, we are in compliance with all financial and non-financial covenants.

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 the Credit Facility. Our ability to comply with the financial ratios and financial condition tests under the 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.

***Borrowings under the Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.***

The borrowing base under the Credit Facility is redetermined at least semiannually and up to two additional times per year between scheduled determinations upon request of us or lenders holding more than 50% of the aggregate commitments. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors.

In our June 2020 redetermination, the borrowing base under the Credit Facility was reduced from $375.0 million to $260.0 million. In our December 2020 redetermination, our most recent one, the borrowing base was reaffirmed at $260.0 million.

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.

***Our exploration, development, exploitation, and production 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, exploitation, and production 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. At this time, we intend to finance future capital expenditures primarily through cash flows provided by operating activities and borrowings under the Credit Facility. 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 or 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 the 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 new and existing wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas;
- 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 the Credit Facility decreases or if our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations. If additional capital is needed, we may not be able to obtain debt or equity financing on favorable terms, or at all. If cash generated by operations or cash available under the 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 an adverse effect on our business, financial condition, and results of operations.

***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, lease, 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 and our ultimate number of prospective well development locations 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, completion, and infrastructure 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 extreme cold temperatures, blizzards, ice storms, tornadoes, floods, and fires;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements, such as permitting delays;
- proximity to and capacity of transportation facilities;
- title problems;
- safety concerns; and
- limitations in the market for oil and natural gas.

***Our estimated proved reserves and our ultimate number of prospective well development locations 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 and the production possible from our oil and gas wells 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, 2020, 2019, and 2018.

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 reserves information contained herein is reviewed by independent reserves 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 cause potential 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.

***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, 2020, 2019, and 2018, 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 for the preceding twelve months (after adjustment for location and quality differentials), 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 activities;
- the amount and timing of actual production;
- the amount and timing of future development costs;
- wellbore productivity realizations above or below type curve forecast models;
- 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.

***As a result of the predominately sustained decrease in prices for oil, natural gas, and NGLs since the fourth quarter of 2014, 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 the middle of 2014 and have not regained previous highs. 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 and completion. Horizontal development operations can be more operationally challenging and costly relative to our historic vertical drilling operations.***

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 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:

- successfully drilling and maintaining the wellbore to planned total depth;
- landing our wellbore in the desired hydrocarbon reservoir;
- effectively controlling the level of pressure flowing from particular wells;
- staying in the desired hydrocarbon reservoir while drilling horizontally through the formation;
- running our casing through the entire length of the wellbore;
- running tools and other equipment consistently through the horizontal wellbore;
- successful design and execution of the fracture stimulation process;
- preventing downhole communications with other wells;
- successfully cleaning out the wellbore after completion of the final fracture stimulation stage; and
- designing and maintaining efficient forms of artificial lift throughout the life of the well.

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.

***We may be unable to make attractive acquisitions, and any inability to do so may disrupt our business and hinder our ability to grow.***

In the future we may make acquisitions of producing properties or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and NGL prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain, and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. In addition, our Credit Facility imposes certain limitations on our ability to enter into mergers or combination transactions. The Credit Facility also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

***The HighPoint Acquisition is subject to a number of regulatory approvals and conditions to the obligations of the parties, which may delay the HighPoint Acquisition, result in additional expenditures of money and resources or reduce the anticipated benefits or result in termination of the Merger Agreement.***

The completion of the HighPoint Acquisition Resources Corporation may be subject to antitrust review in the United States. While no filing or waiting period requirements under the HSR Act apply, the DOJ or the FTC, or any state, could take such action under the antitrust laws as it deems necessary or desirable in the public interest, including seeking to enjoin the completion of the HighPoint Acquisition. Private parties may also seek to take legal action under the antitrust laws under certain circumstances. Our obligations and the obligations of HighPoint to consummate the HighPoint Acquisition are subject to the satisfaction (or waiver by all parties, to the extent permissible under applicable laws) of a number of conditions described in the Merger Agreement. Many of the conditions to completion of the HighPoint Acquisition are not within our control and we cannot predict when, or if, these conditions will be satisfied. If any of these conditions are not satisfied or waived prior to the outside date, it is possible that the Merger Agreement may be terminated.

Although the parties have agreed to use reasonable best efforts, subject to certain limitations, to complete the HighPoint Acquisition as promptly as practicable, these and other conditions may fail to be satisfied. In addition, completion of the merger may take longer, and could cost more, than we expect. The requirements for obtaining the required clearances and approvals could delay the completion of the HighPoint Acquisition for a significant period of time or prevent them from occurring. Any delay in completing the HighPoint Acquisition may adversely affect the cost savings and other benefits that we expect to achieve if the HighPoint Acquisition and the integration of businesses are completed within the expected timeframe.

***The Merger Agreement subjects us to restrictions on our business activities prior to closing the HighPoint Acquisition.***

The Merger Agreement subjects us to restrictions on our business activities prior to closing the HighPoint Acquisition. The Merger Agreement obligates us to generally conduct our businesses in the ordinary course until the closing and to use our reasonable best efforts to (i) preserve substantially intact our present business organization, goodwill and assets, (ii) keep available the services of our current officers and employees and (iii) preserve our existing relationships with governmental entities and significant customers, suppliers, licensors, licensees, distributors, lessors and others having significant business dealings with us. These restrictions could prevent us from pursuing certain business opportunities that arise prior to the closing and are outside the ordinary course of business.

***We may not realize anticipated benefits from acquisitions, including the HighPoint Acquisition.***

We seek to complete acquisitions in order to strengthen our position and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as being able to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations. Acquisitions could also result in difficulties in being able to hire, train or retain qualified personnel to manage and operate such properties.

With respect to the HighPoint Acquisition, we believe that the addition of HighPoint will complement our strategy by providing operational and financial scale, increasing free cash flow, and enhancing our corporate rate of return. However, achieving these goals requires, among other things, realization of the targeted cost synergies expected from the merger, and there can be no assurance that we will be able to successfully integrate HighPoint's assets or otherwise realize the expected benefits of the transaction. This growth and the anticipated benefits of the HighPoint Acquisition may not be realized fully or at all, or may take longer to realize than expected. Difficulties in integrating HighPoint may result in the combined company performing differently than expected, or in operational challenges or failures to realize anticipated efficiencies. Potential difficulties in realizing the anticipated benefits of the HighPoint Acquisition include:

- disruptions of relationships with customers, distributors, suppliers, vendors, landlords, joint venture partners and other business partners as a result of uncertainty associated with the HighPoint Acquisition;

- difficulties integrating our business with the business of HighPoint in a manner that permits us to achieve the full revenue and cost savings anticipated from the transaction;

- complexities associated with managing a larger and more complex business, including difficulty addressing possible inconsistencies in, standards, controls or operational philosophies and the challenge of integrating complex systems, technology, networks and other assets of each of the companies in a seamless manner that minimizes any adverse impact on customers, suppliers, employees and other constituencies;
- difficulties realizing anticipated operating synergies;
- difficulties integrating personnel, vendors and business partners;
- loss of key employees of HighPoint who are critical to our future operations due to uncertainty about their roles within our company following the HighPoint Acquisition or other concerns regarding the HighPoint Acquisition;
- potential unknown liabilities and unforeseen expenses;
- performance shortfalls at one or both of the companies as a result of the diversion of management's attention to integration efforts; and
- disruption of, or the loss of momentum in, each company's ongoing business.

We have also incurred, and expect to continue to incur, a number of costs associated with completing the HighPoint Acquisition and combining the businesses of HighPoint and Bonanza Creek. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the two companies, may not initially offset integration-related costs or achieve a net benefit in the near term, or at all.

Our future success will depend, in part, on our ability to manage our expanded business by, among other things, integrating the assets, operations and personnel of HighPoint and Bonanza Creek in an efficient and timely manner; consolidating systems and management controls; and successfully integrating relationships with customers, vendors and business partners. Failure to successfully manage the combined company may have an adverse effect on our business, reputation, financial condition and results of operations.

***Concentration of our operations in one core area may increase our risk of production loss.***

Our assets and operations are currently concentrated in one core area: the Wattenberg Field in Colorado. The core area currently provides 100% of our current sales volumes and development projects.

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, including ozone non-attainment and climate action regulations in Colorado, curtailment of production, 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. Similarly, the concentration of our assets within a single producing formation exposes us to risks, such as changes in field-wide rules or local regulations, which could adversely affect development activities or production relating to the formation. 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, pressure pumping fleets, 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 our core operating area could have a significant negative impact on our cash flows and profitability.

***As a Colorado-only oil and gas operator, we face disproportionate risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in Colorado.***

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

- delay or denial of drilling permits;
- revocation or modification of drilling permits or other necessary authorizations;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of production, gathering, or processing facilities;
- mandatory and lengthy distances between drilling locations and buildings and/or bodies of water or other protected areas;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposal of related waste materials, such as hydraulic fracturing fluids and produced water;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about us or the oil and gas industry in general;
- increased costs of operations and development;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Specifically in Colorado, anti-development activity has both increased and become more effective in recent years. In April 2019, new legislation became effective in Colorado, which substantially changed the state's regulation of oil and gas exploration and production activities. The new law changed the mission of the COGCC from "fostering" responsible and balanced development to "regulating" oil and natural gas development to protect public health and the environment. The required composition of the COGCC was also changed to remove two seats for oil and gas industry experts and add experts on wildlife/environmental protection and public health, and the Commissioners changed from volunteer to full-time positions. The state's statutory pooling provisions were changed by the new law to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required.

Among the most significant changes under the legislation was the provision of local government control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments may now inspect oil and gas operations and impose fines for leaks, spills, and emissions.

The legislation mandates the COGCC conduct rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned, or shut-in, financial assurance, wellbore integrity, and application fees. The COGCC completed rulemaking on flowlines and wells that are inactive, temporarily abandoned, or shut-in in November 2019, completed rulemaking on wellbore integrity in June 2020, and completed rulemaking on the agency's "mission change" in November 2020. The mission change rulemaking addressed a wide range of topics including facility siting, cumulative impacts, development approvals, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection.

The mission change rules took effect on January 15, 2021, and the agency is currently in the process of issuing written guidance on many of the issues addressed to provide direction on regulatory interpretation and compliance. Among other things, the amended rules adopt an increased required setback of 2,000 feet between an oil and gas location and a residential or high occupancy building unit unless one or more conditions are satisfied to allow for a lesser setback that the COGCC determines is sufficiently protective of public health, safety and welfare, the environment, and wildlife resources. In addition, as part of wildlife protections, the COGCC adopted a setback of 500 feet between oil and gas locations and/or certain operations thereon and the ordinary high water mark for certain high priority aquatic habitats, though the Colorado Parks and Wildlife Division may waive this setback beyond 300 feet.

Permitting delays that result from the new COGCC rules and regulations, could substantially curtail the Company's near-term pace of new oil and gas development. We have previously observed a marked decline in the pace at which permit applications are being granted, and if this trend continues, it could have a material adverse effect on our business, financial condition, and results of operations.

Additionally, the new legislation requires the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds, and nitrogen oxides associated with oil and gas facilities. The AQCC has more recently adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, the development of pre-production air monitoring plans at certain oil and gas facilities, and will soon take action on proposed measures for reducing emissions from pneumatic devices. The legislation also granted the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling, and completion.

Rules adopted by the COGCC and AQCC pursuant to the new legislation may significantly increase the Company's operating costs and have a material adverse effect on our business, financial condition, and results of operations.

Additionally, anti-development activists succeeded in adding a measure to the November 6, 2018 ballot in Colorado, which sought to require a minimum 2,500 foot setback from occupied structures and vulnerable areas for all new oil and gas development on non-federal land. While this initiative was ultimately unsuccessful, had it been successful, it may have resulted in dramatically reducing the area of future oil and gas development in Colorado. Similar ballot measures were submitted for the 2020 election by anti-development activist groups. In addition, there have been several citizen/activist lawsuits filed against industry and state and local regulators associated with air quality, siting, environmental justice, and climate change. Such anti-development efforts are likely to continue in the future, which could result in dramatically reducing the area of future oil and gas development in Colorado or outright banning oil and gas development in Colorado. These efforts could have a material adverse effect on our business, financial condition, and results of operations.

***State law requiring that we own or control more than 45% of the working or mineral interest in order to statutorily pool our applicable interest may make it much more difficult for us to develop such interests, which could have a material adverse effect on our business, financial condition, and results of operations.***

In many cases, we do not own more than 45% working interest or mineral interest in a prospective area of development, which is now required to statutorily pool our applicable working or mineral interests. In such cases, unless we can obtain the consent of more than 45% of all applicable working or mineral interest owners (who can be located through reasonable diligence) to pursue statutory pooling, or achieve a voluntary pooling agreement with 100% of the applicable interest owners, we may be prohibited from developing the resources in that area.

***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. For example, we will not operate the majority of our assets in the French Lake area. 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.

***The concentrated nature of our RMI system may increase the risk that we suffer lengthy interruptions in our production.***

Through our Rocky Mountain Infrastructure, LLC ("RMI") subsidiary, we have consolidated and interconnected our gathering, treating, and production facilities. This approach includes, for example, greater use of central processing facilities and central compression stations than some other operators in the Wattenberg Field. The concentrated nature of the RMI system, by itself, could increase the length and magnitude of a production interruption caused by operational problems located in otherwise localized portions of the system. Such interruptions could materially and adversely affect our ability to meet our public guidance, our financial condition, and our results of operations.

***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 50% of our total proved reserves were classified as proved undeveloped as of December 31, 2020. 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.

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

***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 draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing, and operating any well is often uncertain, and new wells may not be productive.

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

The terms of our oil and gas leases often stipulate that the lease will terminate if not held by production, rentals, or some form of an extension payment to extend the term of the lease. As of December 31, 2020, approximately 3,705 net acres of our properties were not held by production. For these properties, if production in paying quantities is not established on units containing leases during the next year, then approximately 1,859 net acres will expire in 2021, approximately 1,356 net acres will expire in 2022, and approximately 490 net acres will expire in 2023 and thereafter. While some expiring leases may contain predetermined extension payments, other expiring leases will require us to negotiate new leases at the time of lease expiration. It is possible that market conditions at the time of negotiation could require us to agree to new leases on less favorable terms to us than the terms of the expired leases or cause us to lose the leases entirely. If our leases expire, we will lose our right to develop the related properties.

***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.

***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 soil, surface water, groundwater, and shoreline contamination;
- releases of natural gas and hazardous air pollutants or other substances into the atmosphere (including releases at our oil and gas facilities);
- hazards resulting from the presence of hydrogen sulfide ($H_2S$) or other contaminants in natural gas and oil we produce;
- abnormally pressured formations resulting in well blowouts, fires, or explosions;
- mechanical difficulties, such as stuck down-hole tools or casing collapse;
- cratering (catastrophic failure);
- downhole communication leading to migration of contaminants;
- personal injuries and death; and
- natural disasters.

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

- injury or loss of life;
- damage to and destruction of property, natural resources, and equipment;
- pollution and other environmental and natural resource 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 and facility locations. In addition, our operations in Colorado are susceptible to damage from natural disasters, such as flooding, wildfires, tornadoes, and other natural phenomena and weather conditions, including extreme temperatures, 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 integral to 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. We also do not 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.

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

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

There is an inherent risk of incurring significant environmental costs and liabilities in our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions into air, water and the environment, the underground injection or other disposal of our wastes, the use and disposition of hydraulic fracturing fluids, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable for the full cost of removing or remediating contamination, regardless of whether we were at fault, and even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws then in effect. In addition, accidental spills or releases on or off our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Aside from government agencies, the owners of properties where our wells are located, the owners or operators of facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal or otherwise come to be located, and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, collect penalties for violations, or obtain damages for any related personal injury, or damage and property damage, and certain trustees may seek natural resource damages. Some sites we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that historic contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise have a material adverse effect on our own results of operations, competitive position, or financial condition. We may not be able to recover some or any of these costs from insurance.

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

We are subject to extensive federal, state, and local laws and regulations concerning health, safety, and environmental protection. Governmental authorities frequently add to those requirements, and both oil and gas development generally, and hydraulic fracturing specifically, are receiving increasing regulatory attention. For example, during 2020, the COGCC revised its regulations on a range of topics including facility siting, development approvals, cumulative impacts, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection. And legislation passed in 2019 requires the COGCC to assess and potentially revise its financial assurance requirements for oil and gas development. 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.

Some activists have attempted to link hydraulic fracturing to various environmental problems, including potential adverse effects to drinking water supplies, migration of methane and other hydrocarbons into groundwater, increased seismic activity, and human health effects. The federal government has periodically studied the environmental risks associated with hydraulic fracturing and evaluated whether to adopt, and in some cases have adopted, additional regulatory requirements.

In some instances certain state and local governments are adopting new requirements on hydraulic fracturing and other oil and gas operations. Some counties in Colorado, for instance, have amended their land use regulations to impose new requirements on oil and gas development, while other local governments have entered memoranda of agreement with oil and gas producers to accomplish the same objective. Under current Colorado law, local governments can regulate both facility siting and the surface impacts associated with oil and gas development, and local government regulations may be more protective or stricter than State requirements. In addition, voters in Colorado have proposed or advanced ballot initiatives restricting or banning oil and gas development in Colorado. Because our operations and reserves are solely located in Colorado, the risks we face with respect to such ballot initiatives are greater than other companies with more geographically diverse operations.

The adoption of future federal, state, or local laws or implementing regulations imposing new environmental and financial assurance 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 operations, 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. We cannot assure that any such outcome would not be material, and any such outcome could have a material adverse impact on our cash flows and results of operations.

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

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

The EPA also adopted regulations requiring the reporting of GHG emissions from specific categories of higher GHG emitting sources in the United States, including certain oil and natural gas production facilities, which include certain of our operations. Information in such reporting may form the basis for further GHG regulation. Further, the EPA has continued with its comprehensive strategy for further reducing methane emissions from oil and gas operations, with a final rule being issued in May 2016 as part of the Subpart OOOOa NSPS rules discussed above. The EPA’s GHG rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

In the meantime, many states already have taken such measures, which have included renewable energy standards, development of GHG emission inventories or cap and trade programs, and the adoption of ambitious climate action targets in Colorado under HB 19-1261. Cap and trade programs typically work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of available allowances reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. Such a program has been proposed by an environmental group to the Colorado AQCC in a petition filed on December 23, 2020. The AQCC will consider action on that petition later in 2021.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions and vapor control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in oil and natural gas activities.

***The negative shift in investor sentiment of the oil and gas industry could have adverse effects on our ability to raise debt and equity capital and on our operations.***

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Additionally, negative public perception regarding us and/or our industry may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business. Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

***We are exposed to credit risks of our hedging counterparties, third parties participating in our wells, and our customers.***

Our principal exposures to credit risk are through receivables resulting from commodity derivatives instruments, joint interest billings, and other components of $14.7 million at December 31, 2020, and the sale of our oil, natural gas, and NGLs production of $32.7 million in receivables at December 31, 2020, which we market to energy marketing companies, refineries, and affiliates.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells.

We are also subject to credit risk due to concentration of our oil, natural gas, and NGLs receivables with significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2020, sales to NGL Crude Logistics, LLC comprised 77% of our total sales. Through 2023, we have contracted to sell up to 16,000 barrels per day of our crude oil produced in the Wattenberg Field to NGL Crude Logistics, LLC.

We are exposed to credit risk in the event of default of our counterparty, principally with respect to hedging agreements, but also with respect to insurance contracts and bank lending commitments. We do not require most of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

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

The Dodd-Frank Act establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. The Dodd-Frank Act may require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative as a result of the Dodd-Frank Act and regulations, our results of operations may be more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

***We may be involved in legal cases that may result in substantial liabilities.***

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

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

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

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

In Colorado, there may be proposals for legislative changes that, if enacted into law, could substantially increase our severance tax and ad valorem tax effective rates. Such changes may include, but are not limited to, (i) the reduction or elimination of the credit against severance tax based on the property tax we pay; (ii) the reduction or elimination of certain exemptions impacting severance tax liability; and (iii) increased severance tax rates. Any such changes to Colorado's ad valorem and severance tax laws could negatively affect our financial condition, results of operations, and cash flow.

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

***The transactions in connection with the HighPoint Acquisition could trigger a limitation on the utilization of our historic U.S. net operating loss carryforwards and will trigger a limitation on the utilization of HighPoint's historic U.S. net operating loss carryforwards.***

Our ability to utilize U.S. net operating loss carryforwards (including any historic loss carryforwards of HighPoint) to reduce future taxable income following the HighPoint Acquisition will be subject to various limitations under the Code. Section 382 of the Code imposes such a limitation upon the occurrence of an ownership change resulting from issuances of a company's stock or the sale or exchange of such company's stock by certain stockholders if, as a result, there is an aggregate change of more than 50% in the beneficial ownership of such company's stock by such stockholders within a rolling three-year period. The limitation with respect to such loss carryforwards generally would be equal to (i) the fair market value of the company's equity multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax-exempt bonds during the month in which the ownership change occurs. In addition, any limitation would be increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold, and further, if there is a net unrealized built-in loss at the time of an ownership change, then the limitation may apply to tax attributes other than just loss carryforwards, such as depreciable basis. Based on the information currently available, we believe that the transactions in connection with the HighPoint Acquisition, if consummated, likely will not result in an ownership change with respect to us but will result in an ownership change with respect to HighPoint, which would trigger a limitation on our ability to utilize any historic loss carryforwards and built-in losses of HighPoint following the HighPoint Acquisition.

However, issuances, sales and/or exchanges of our common stock (including, potentially, relatively small transactions and transactions beyond our control), taken together with prior transactions with respect to our common stock and the HighPoint Acquisition, could trigger an ownership change and therefore a limitation on our ability to utilize its U.S. loss carryforwards. We adopted the tax plan to reduce the likelihood that we would experience an ownership change under Section 382 of the Code. However, if we experience an ownership change, any resulting limitation under Section 382 of the Code could cause some of such loss carryforwards to expire before we would be able to utilize them to reduce taxable income in future periods, possibly resulting in a substantial income tax expense or write down of our tax assets or both.

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

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

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

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

**Risks Relating to our Common Stock**

***The market price for our common stock following the HighPoint Acquisition may be affected by factors different from those that historically have affected or currently affect our common stock, including that Franklin will be a significant holder of our common stock.***

Our financial position following the HighPoint Acquisition may differ from our financial position before the HighPoint Acquisition, and the results of operations of the combined company may be affected by factors that are different from those currently affecting the results of our operations. Accordingly, the market price and performance of our common stock is likely to be different from the performance of our common stock in the absence of the HighPoint Acquisition.

Upon the closing of the HighPoint Acquisition, holders of HighPoint senior notes will receive shares of our common stock as consideration. Assuming there is no decrease in the holdings of Franklin Advisors, Inc. ("Franklin") of HighPoint senior notes, Franklin is expected to own approximately 22.7% of our common stock following the HighPoint Acquisition. As a result, although Franklin has indicated to us that it intends to be a passive investor, we believe that Franklin may have some ability to influence our management and affairs. Further, the existence of a new significant stockholder may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may view as being in their or our best interests. In any matters requiring approval or our stockholders, the interests of Franklin and of our other stockholders may differ or conflict, and Franklin and its affiliates may, from time to time, acquire interests in businesses that directly or indirectly compete with us or our existing or potential customers. Moreover, if Franklin becomes and continues to be the owner of a significant concentration of our common stock, such an ownership stake may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

***We do not currently intend to pay, and are subject to certain restrictions on our ability to pay, dividends on our common stock, and consequently, our stockholders' likely only opportunity to achieve a return on their investment is if the price of our stock appreciates.***

Currently, we do not plan to declare dividends on shares of our common stock. Additionally, our Credit Facility places certain restrictions on our ability to pay dividends. Consequently, our stockholders' opportunity to achieve a return on their investment in us will rely upon the appreciation of the market price of our common stock, which may not occur, and the stockholders selling their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the stockholders paid.

***We have experienced recent volatility in the market price and trading volume of our common stock and may continue to do so in the future.***

The trading price of shares of our common stock has fluctuated widely and in the future may be subject to similar fluctuations. As an example, during the 2020 calendar year, the sales price of our common stock ranged from a low of $8.25 per share to a high of $25.80 per share. The trading price of our common stock may be affected by a number of factors, including the volatility of oil, natural gas, and NGL prices, our operating results, changes in our earnings estimates, additions or departures of key personnel, our financial condition and liquidity, drilling activities, legislative and regulatory changes, general conditions in the oil and natural gas exploration and development industry, general economic conditions, and general conditions in the securities markets. In particular, a significant or extended decline in oil, natural gas, and NGL prices could have a material adverse effect our sales price of our common stock. Other risks described in this annual report could also materially and adversely affect our share price.

Although our common stock is listed on the New York Stock Exchange, we cannot assure you that an active public market will continue for our common stock or that we will be able to continue to meet the listing requirements of the NYSE. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us.

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

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

- advance notice provisions for stockholder proposals and nominations for elections to the Board to be acted upon at meetings of stockholders; and
- limitations on the ability of our stockholders to call special meetings or act by written consent.

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

***Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees.***

Our certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum shall be the Court of Chancery of the State of Delaware for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer, employee or agent of ours to us or to our stockholders, (iii) any action asserting a claim against us arising pursuant to any provision of the DGCL, our certificate of incorporation or our bylaws (or any action to interpret, apply or enforce any provision thereof), or (iv) any action asserting a claim against us governed by the internal affairs doctrine, in each such case subject to said court of chancery having personal jurisdiction over the indispensable parties named as defendants therein.

Our exclusive forum provision is not intended to apply to claims arising under the Securities Act or the Exchange Act. To the extent the provision could be construed to apply to such claims, there is uncertainty as to whether a court would enforce the forum selection provision with respect to such claims, and in any event, our stockholders would not be deemed to have waived our compliance with federal securities laws and the rules and regulations thereunder. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock is deemed to have received notice of and consented to the foregoing forum selection provision. This provision may limit our stockholders' ability to bring a claim in a judicial forum that they find favorable for disputes with us or our directors, officers, or other employees, which may discourage such lawsuits. Alternatively, if a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition, prospects, or results of operations.

**Item 1B.** ***Unresolved Staff Comments.***

None.

**Item 2.** ***Properties.***

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

**Item 3.** ***Legal Proceedings.***

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

**Item 4.** ***Mine Safety Disclosures.***

Not applicable.

# PART II

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

*Market for Registrant's Common Equity.* Our common stock is listed on the NYSE under the symbol "BCEI".

*Holders.* As of February 15, 2021, there were approximately 30 registered holders of our common stock.

*Dividends.* We have not paid any cash dividends since our inception. Covenants contained in our Credit Facility restrict the payment of cash dividends on our common stock, as discussed further in *Part II, Item 7, Liquidity and Capital Resources*. We currently intend to retain all future earnings for the development and growth of our business, and we do not currently anticipate declaring or paying any cash dividends to holders of our common stock.

*Issuer Purchases of Equity Securities.* The following table contains information about our acquisition of equity securities during the three months ended December 31, 2020.

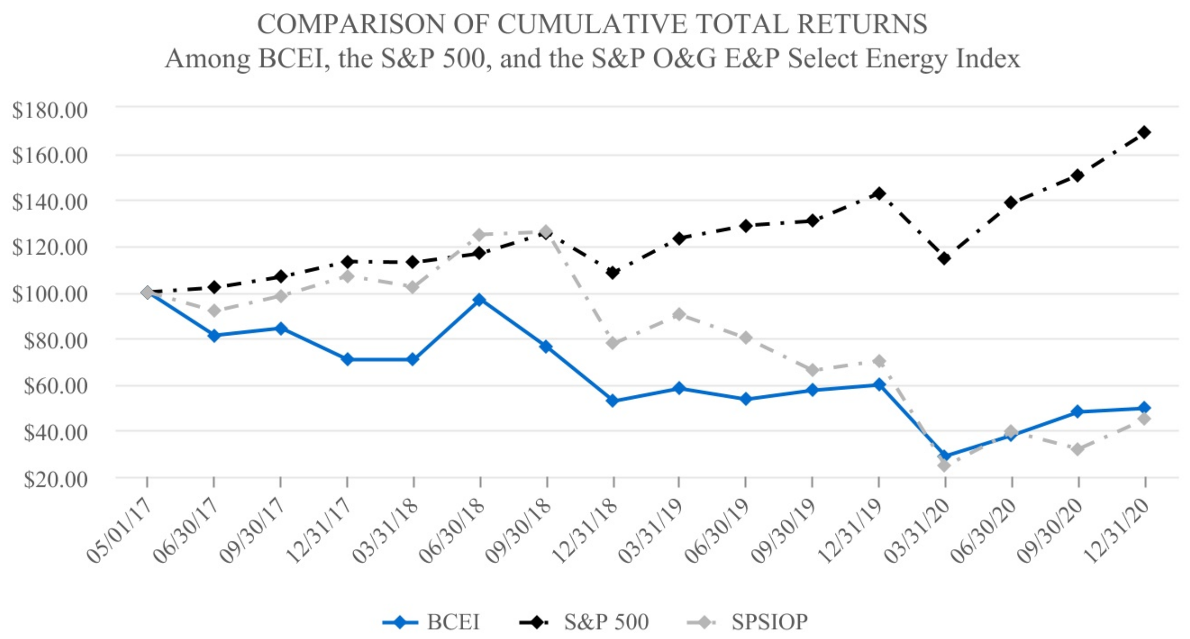
| | Total Number of Shares Purchased[(1)] | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number of Shares that May Be Purchased Under Plans or Programs |
|---|---|---|---|---|
| October 1, 2020 - October 31, 2020 | 163 | $ 20.53 | — | — |
| November 1, 2020 - November 30, 2020 | 1,353 | $ 22.19 | — | — |
| December 1, 2020 - December 31, 2020 | 608 | $ 21.81 | — | — |
| Total | 2,124 | $ 21.59 | — | — |

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

*Sale of Unregistered Securities.* We had no sales of unregistered securities during the year ended December 31, 2020.

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

The following graph compares the cumulative total stockholder return for the Company's common stock, the Standard and Poor's 500 Stock Index (the "S&P 500 Index") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P Index"). The measurement points in the graph below are May 1, 2017 (the first trading day of our common stock on the NYSE upon emergence) and each fiscal quarter thereafter through December 31, 2020. The graph assumes that $100 was invested on May 1, 2017 in each of the common stock of the Company, the S&P 500 Index, and the S&P O&G E&P Index and assumes reinvestment of any dividends. The stock price performance on the following graph is not necessarily indicative of future stock price performance.



**Item 6.** ***[Reserved].***

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

The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. Such forward-looking statements should be read in conjunction with our disclosures under "Item 1A. Risk Factors" of this Form 10-K.

This section of this Form 10-K generally discusses 2020 and 2019 results and year-to-year comparisons between 2020 and 2019. Discussions of 2018 items and year-to-year comparisons between 2019 and 2018 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of Bonanza Creek's Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

**Executive Summary**

We are an independent Denver-based exploration and production company focused on the acquisition, development, and extraction of oil and associated liquids-rich natural gas in the United States. Our oil and liquids-weighted assets and operations are concentrated in the rural portions of the Wattenberg Field in Colorado. Our development and extraction activities are primarily directed at the horizontal development of the Niobrara and Codell formations in the DJ Basin. The majority of our revenues are generated through the sale of oil, natural gas, and natural gas liquids production.

The Company's primary objective is to maximize shareholder returns by responsibly developing our oil and gas resources. We seek to balance production growth with maintaining a conservative balance sheet. Key aspects of our strategy include multi-well pad development across our leasehold, enhanced completions through continuous design evaluation, utilization of scaled infrastructure, continuous safety improvement, strict adherence to health and safety regulations, and environmental stewardship.

**Financial and Operating Results**

Our 2020 financial and operational results include:

- General and administrative expense per Boe decreased by 18% for the year ended December 31, 2020 when compared to the same period during 2019;
- Lease operating expense decreased by $3.3 million or $0.57 per Boe for the year ended December 31, 2020 when compared to the same period during 2019;
- Crude oil equivalent sales volumes increased 8% for the year ended December 31, 2020 when compared to the same period during 2019, despite the significant curtailment of our drilling and completion program in response to the drop in commodity prices;
- Borrowings under our Credit Facility were reduced by $80.0 million to zero during the year ended December 31, 2020;
- Total liquidity was $284.7 million at December 31, 2020, consisting of cash on hand plus funds available under our Credit Facility. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Cash flows provided by operating activities for the year ended December 31, 2020 was $158.8 million, as compared to cash flows provided by operating activities of $224.6 million during the year ended December 31, 2019. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Proved reserves of 118.2 MMBoe as of December 31, 2020 decreased by 3% when compared to proved reserves as of December 31, 2019; and
- Capital expenditures, inclusive of accruals, were $67.7 million during the year ended December 31, 2020, which was within guidance.

**Rocky Mountain Infrastructure**

The Company's gathering, treating, and production facilities, maintained under its Rocky Mountain Infrastructure, LLC ("RMI") subsidiary, provide many operational benefits to the Company and provide cost economies of a centralized system. The RMI facilities reduce gathering system pressures at the wellhead, thereby improving hydrocarbon recovery. Additionally, with eleven interconnects to four different natural gas processors, RMI helps ensure that the Company's production is not constrained by any single midstream service provider. Furthermore, in 2019, the Company installed a new oil gathering line to Riverside Terminal (on the Grand Mesa Pipeline), which resulted in a corresponding $1.25 to $1.50 per barrel reduction to our oil differentials for barrels transported on such gathering line. The total value of reduced oil differentials during the year ended December 31, 2020 was approximately $6.2 million. Finally, the RMI system reduces facility site footprints, leading to more cost-efficient operations, reduced emissions, and reduced surface disturbance. The net book value of the Company's RMI assets was $153.0 million as of December 31, 2020.

**Current Events and Outlook**

The worldwide outbreak of COVID-19, the uncertainty regarding the impact of COVID-19, and various governmental actions taken to mitigate the impact of COVID-19, have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production further increased the excess supply of oil and natural gas. Due to the decline in crude oil prices and ongoing uncertainty regarding the oil supply-demand macro environment as a result of these events, we have suspended all drilling and significantly reduced completion and infrastructure activities.

The COVID-19 outbreak and its development into a pandemic in March 2020 have also required that we take precautionary measures intended to help minimize the risk to our business, employees, customers, suppliers, and the communities in which we operate. Our operational employees are currently still able to work on site. However, we have taken various precautionary measures with respect to our operational employees such as requiring them to verify they have not experienced any symptoms consistent with COVID-19, or been in close contact with someone showing such symptoms, before reporting to the work site, quarantining any operational employees who have shown signs of COVID-19 (regardless of whether such employee has been confirmed to be infected), and imposing social distancing requirements on work sites, all in accordance with the guidelines released by the Centers for Disease Control and Prevention. We have not yet experienced any material operational disruptions (including disruptions from our suppliers and service providers) as a result of a COVID-19 outbreak.

Due to the unprecedented drop in commodity prices that commenced in early March 2020, the Company updated its 2020 operating plan and reduced planned development activity including limited drilling and completion activity that concluded in March 2020, with a small amount of additional completion work done in July 2020.

In further response to the drop in commodity prices, our named executive officers and independent directors voluntarily reduced their compensation. Effective in early April 2020, our Chief Executive Officer's salary was reduced by 12.5%, the other named executive officers' salaries were each reduced by 10%, and our independent directors' base annual cash retainers were reduced by 15%. In addition, the Company completed a 12% reduction in its workforce during the second quarter. Finally, the Company implemented approximately $8 million in LOE and RMI operating expense savings compared to the Company's original 2020 plan.

The Company's first quarter 2021 capital budget of $35 million to $40 million assumes the beginning of completion activities on 30 gross (25.8 net) drilled, uncompleted wells. The Company is providing guidance for the first quarter of 2021 for Bonanza Creek as a stand-alone company. Additional guidance for 2021 on a combined basis will be provided after the closing of the HighPoint Acquisition. Actual capital expenditures could vary significantly based on, among other things, market conditions, commodity prices, drilling and completion costs, and well results.

**Results of Operations**

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

The following table summarizes our product revenues, sales volumes, and average sales prices for the periods indicated:

| | Year Ended December 31, 2020 | Year Ended December 31, 2019 | Change | Percent Change |
|---|---|---|---|---|
| **Revenues (in thousands):** | | | | |
| Crude oil sales[1] | $ 172,787 | $ 266,480 | $ (93,693) | (35)% |
| Natural gas sales[2] | 20,562 | 24,624 | (4,062) | (16)% |
| Natural gas liquids sales | 19,311 | 16,060 | 3,251 | 20 % |
| Product revenue | $ 212,660 | $ 307,164 | $ (94,504) | (31)% |
| **Sales Volumes:** | | | | |
| Crude oil (MBbls) | 5,019.4 | 5,135.9 | (116.5) | (2)% |
| Natural gas (MMcf) | 14,165.7 | 11,966.8 | 2,198.9 | 18 % |
| Natural gas liquids (MBbls) | 1,858.2 | 1,431.1 | 427.1 | 30 % |
| Crude oil equivalent (MBoe)[3] | 9,238.6 | 8,561.5 | 677.1 | 8 % |
| **Average Sales Prices (before derivatives)[4]:** | | | | |
| Crude oil (per Bbl) | $ 34.42 | $ 51.89 | $ (17.47) | (34)% |
| Natural gas (per Mcf) | $ 1.45 | $ 2.06 | $ (0.61) | (30)% |
| Natural gas liquids (per Bbl) | $ 10.39 | $ 11.22 | $ (0.83) | (7)% |
| Crude oil equivalent (per Boe)[3] | $ 23.02 | $ 35.88 | $ (12.86) | (36)% |
| **Average Sales Prices (after derivatives)[4]:** | | | | |
| Crude oil (per Bbl) | $ 44.41 | $ 52.12 | $ (7.71) | (15)% |
| Natural gas (per Mcf) | $ 1.40 | $ 2.10 | $ (0.70) | (33)% |
| Natural gas liquids (per Bbl) | $ 10.39 | $ 11.22 | $ (0.83) | (7)% |
| Crude oil equivalent (per Boe)[3] | $ 28.37 | $ 36.07 | $ (7.70) | (21)% |

(1) Crude oil sales excludes $1.7 million and $2.4 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2020 and 2019, respectively.
(2) Natural gas sales excludes $3.7 million and $3.7 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2020 and 2019, respectively.
(3) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.
(4) Derivatives economically hedge the price we receive for crude oil and natural gas. For the year ended December 31, 2020, the derivative cash settlement gain for oil was $50.1 million, and the derivative cash settlement loss for natural gas contracts was $0.7 million. For the year ended December 31, 2019, the derivative cash settlement gain for oil and natural gas was $1.2 million and $0.5 million, respectively. Please refer to *Part II, Item 8, Note 12 - Derivatives* for additional disclosures.

Product revenues decreased by 31% to $212.7 million for the year ended December 31, 2020 compared to $307.2 million for the year ended December 31, 2019. The decrease was largely due to a $12.86 or 36% decrease in oil equivalent pricing excluding the impact of derivatives, partially offset by an 8% increase in sales volumes. The increase in sales volumes is due to turning 26 gross wells to sales during the year ending December 31, 2020.

The following table summarizes our operating expenses for the periods indicated (in thousands, except per Boe amounts):

| | Year Ended December 31, 2020 | Year Ended December 31, 2019 | Change | Percent Change |
|---|---|---|---|---|
| **Operating Expenses:** | | | | |
| Lease operating expense | $ 21,957 | $ 25,249 | $ (3,292) | (13)% |
| Midstream operating expense | 14,948 | 12,014 | 2,934 | 24 % |
| Gathering, transportation, and processing | 16,932 | 16,682 | 250 | 1 % |
| Severance and ad valorem taxes | 3,787 | 25,598 | (21,811) | (85)% |
| Exploration | 596 | 797 | (201) | (25)% |
| Depreciation, depletion, and amortization | 91,242 | 76,453 | 14,789 | 19 % |
| Abandonment and impairment of unproved properties | 37,343 | 11,201 | 26,142 | 233 % |
| Bad debt expense | 818 | — | 818 | 100 % |
| Merger transaction costs | 6,676 | — | 6,676 | 100 % |
| General and administrative expense | 34,936 | 39,668 | (4,732) | (12)% |
| Operating expenses | $ 229,235 | $ 207,662 | $ 21,573 | 10 % |
| | | | | |
| **Selected Costs ($ per Boe):** | | | | |
| Lease operating expense | $ 2.38 | $ 2.95 | $ (0.57) | (19)% |
| Midstream operating expense | 1.62 | 1.40 | 0.22 | 16 % |
| Gathering, transportation, and processing | 1.83 | 1.95 | (0.12) | (6)% |
| Severance and ad valorem taxes | 0.41 | 2.99 | (2.58) | (86)% |
| Exploration | 0.06 | 0.09 | (0.03) | (33)% |
| Depreciation, depletion, and amortization | 9.88 | 8.93 | 0.95 | 11 % |
| Abandonment and impairment of unproved properties | 4.04 | 1.31 | 2.73 | 208 % |
| Bad debt expense | 0.09 | — | 0.09 | 100 % |
| Merger transaction costs | 0.72 | — | 0.72 | 100 % |
| General and administrative expense | 3.78 | 4.63 | (0.85) | (18)% |
| Operating expenses | $ 24.81 | $ 24.25 | $ 0.56 | 2 % |
| | | | | |
| Operating expenses, excluding impairments and abandonments and unused commitments | $ 20.77 | $ 22.94 | $ (2.17) | (9)% |

*Lease operating expense.* Our lease operating expense decreased $3.3 million, or 13%, to $22.0 million for the year ended December 31, 2020 from the year ended December 31, 2019, and decreased on an equivalent basis per Boe by 19%. The overall decrease was primarily due to reductions in pumping and gauging costs, compression costs, and several other areas implemented by the Company in a concerted effort to reduce costs in response to the decline in commodity pricing. Lease operating expense per unit decreased on a higher percentage basis due to oil equivalent sales volumes being 8% higher during the year ended December 31, 2020 as compared to the same period in 2019.

*Midstream operating expense.* Our midstream operating expense increased $2.9 million to $14.9 million for the year ended December 31, 2020 from $12.0 million for the year ended December 31, 2019, and increased on an equivalent basis per Boe by 16%. The increase was primarily due to a full year of costs associated with the Company's new and expanded oil gathering line connected to the Riverside Terminal that came online in July 2019.

*Gathering, transportation, and processing.* Gathering, transportation, and processing expense increased by $0.2 million to $16.9 million for the year ended December 31, 2020 from $16.7 million for the year ended December 31, 2019. Natural gas and NGLs sales volumes have a direct correlation to gathering, transportation, and processing expense. Although natural gas and NGLs sales volumes increased 23% between the comparable periods, a decline in fees on sales contracts partially offset the increase in gathering, transportation, and processing expense.

*Severance and ad valorem taxes.* Our severance and ad valorem taxes decreased by 85% to $3.8 million for the year ended December 31, 2020 from $25.6 million for the year ended December 31, 2019. Severance and ad valorem taxes primarily correlate to revenue. Revenues decreased by 31% for the year ended December 31, 2020 when compared to the same period in 2019. Additionally, during 2020, we refined our tax estimate based on current mill levies, taxing districts, and company results based on commodity prices, which resulted in a total non-recurring adjustment of $16.3 million. Excluding this adjustment, our severance and ad valorem taxes were $20.1 million for the year ended December 31, 2020, which is aligned with the reduction in revenues.

*Depreciation, depletion, and amortization.* Our depreciation, depletion, and amortization expense increased 19% to $91.2 million for the year ended December 31, 2020 from $76.5 million for the year ended December 31, 2019, and increased 11% on a per Boe basis during the comparable period. The increase in depreciation, depletion, and amortization expense is the result of (i) a $121.7 million increase in the depletable property base and (ii) an increase in the depletion rate driven by an 8% increase in production between the comparable periods.

*Abandonment and impairment of unproved properties.* During the years ended December 31, 2020 and 2019, we incurred $37.3 million and $11.2 million in abandonment and impairment of unproved properties primarily due to the reassessment of estimated probable and possible reserve locations based primarily upon economic viability and the expiration of non-core leases. Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* for additional discussion on our impairment policy and practices.

*Merger transaction costs.* During the year ended December 31, 2020, we incurred $6.7 million in legal, advisor, and other costs associated with the anticipated HighPoint Acquisition compared to no such costs during the comparable 2019 period.

*General and administrative expense.* Our general and administrative expense decreased by $4.8 million to $34.9 million for the year ended December 31, 2020, compared to $39.7 million for the year ended December 31, 2019, and decreased by 18% on a per Boe basis between the comparable periods. The decrease in general and administrative expense between the comparable periods is primarily due to a decrease in salaries, benefits, and stock compensation expense due to our reduced workforce, partially offset by an increase in severance costs. General and administrative expense per Boe decreased on a higher percentage basis due to oil equivalent sales volumes being 8% higher during the year ended December 31, 2020 as compared to the same period in 2019.

*Derivative gain (loss).* Our derivative gain for the year ended December 31, 2020 was $53.5 million as compared to a loss of $37.1 million for year ended December 31, 2019. Our derivative gain is due to settlements and fair market value adjustments caused by market prices being lower than our contracted hedge prices. Please refer to *Part II, Item 8, Note 12 - Derivatives* for additional discussion.

*Interest expense.* Our interest expense for the years ended December 31, 2020 and 2019 was $2.0 million and $2.7 million, respectively. Average debt outstanding for the years ended December 31, 2020 and 2019 was $53.2 million and $77.2 million, respectively. The components of interest expense for the periods presented are as follows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Credit Facility | $ 1,760 | $ 3,450 |
| Commitment fees on available borrowing base under the Credit Facility | 1,181 | 1,112 |
| Amortization of deferred financing costs | 864 | 494 |
| Capitalized interest | (1,760) | (2,406) |
| Total interest expense, net | $ 2,045 | $ 2,650 |

**Liquidity and Capital Resources**

The Company's anticipated sources of liquidity include cash from operating activities, borrowings under the Credit Facility, proceeds from sales of assets, and potential proceeds from equity and/or debt capital markets. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity, regulatory constraints, and other supply chain dynamics, among other factors. To mitigate some of the pricing risk, we have hedged approximately 6,200 Bbls per day in 2021, representing approximately 50% of our oil sales volume during the three months ended December 31, 2020.

As of December 31, 2020, our liquidity was $284.7 million, consisting of cash on hand of $24.7 million and $260.0 million of available borrowing capacity on our Credit Facility. Please refer to *Part II, Item 8, Note 6 - Long-term Debt* for additional discussion.

We anticipate investing approximately $35 million to $40 million, which will support the beginning of completion activities on 30 gross (25.8 net) wells in the first quarter of 2021 as a stand-alone company. Additional guidance for 2021 on a combined basis will be provided after the closing of the HighPoint Acquisition.

The following table summarizes our cash flows and other financial measures for the periods indicated (in thousands):

| | Year Ended December 31, 2020 | Year Ended December 31, 2019 |
|---|---|---|
| Net cash provided by operating activities | $ 158,796 | $ 224,647 |
| Net cash used in investing activities | (63,799) | (255,158) |
| Net cash provided by (used in) financing activities | (81,247) | 28,604 |
| Cash, cash equivalents, and restricted cash | 24,845 | 11,095 |
| Acquisition of oil and gas properties | (3,210) | (14,087) |
| Exploration and development of oil and gas properties | (60,149) | (242,487) |

*Cash flows provided by operating activities*

For the years ended December 31, 2020 and 2019, the cash receipts and disbursements were attributable to our normal operating cycle. See *Results of Operations* above for more information on the factors driving these changes.

*Cash flows used in investing activities*

Expenditures for development of oil and natural gas properties are the primary use of our capital resources. The Company spent $60.1 million and $242.5 million on the exploration and development of oil and gas properties during the years ended December 31, 2020 and 2019, respectively. The decrease in capital expenditures between the periods is primarily due to reduced drilling and completion activity in response to the unprecedented drop in commodity prices between the comparable periods. The Company also spent $10.9 million less on acquisitions of oil and gas properties during the year ended December 31, 2020 when compared to the same period in 2019.

*Cash flows provided by financing activities*

Net cash used in financing activities for the year ended December 31, 2020 was $81.2 million, compared to cash provided by financing activities for the year ended December 31, 2019 of $28.6 million. The change was primarily due to a $110.0 million increase in net payments on our Credit Facility between the comparable periods.

*Material Commitments*

We had the following material commitments as of December 31, 2020 (in thousands):

| | Total | Less than 1 Year | 1-3 Years | 3-5 Years | More than 5 Years |
|---|---|---|---|---|---|
| Delivery commitments[(1)] | $ 49,701 | $ 22,403 | $ 27,298 | $ — | $ — |
| Operating leases[(2)] | 31,542 | 12,836 | 16,159 | 2,547 | — |
| Asset retirement obligations[(3)] | 28,699 | — | 14,774 | 396 | 13,529 |
| Total | $ 109,942 | $ 35,239 | $ 58,231 | $ 2,943 | $ 13,529 |

(1) The calculation on the delivery commitments is based on the minimum gross volume commitment schedule (as defined in the NGL Crude agreement) and applicable differential fees. Please refer to *Note 7 - Commitments and Contingencies* for additional discussion on this agreement.
(2) The Company has included the minimum future commitments for its long-term operating leases. Such leases are reflected at undiscounted values. Please refer to *Part II, Item* 8, *Note 2 - Leases*, for additional discussion.
(3) Amounts represent our estimated future retirement obligations on a discounted basis. The discounted obligations are recorded as liabilities on our accompanying balance sheets as of December 31, 2020 and 2019. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. Please refer to *Part II, Item* 8, *Note 10 - Asset Retirement Obligation*, for additional discussion.

*Credit Facility*

In December 2018, the Company entered into a reserve-based revolving facility, as the borrower, with JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions, as lenders. The $750.0 million Credit Facility has a maturity date of December 7, 2023 and was governed by an initial borrowing base of $350.0 million. The Credit Facility borrowing base is redetermined on a semi-annual basis. In June 2020, the borrowing base and aggregate elected commitments were reduced to $260.0 million. The most recent redetermination was concluded on December 18, 2020, resulting in a reaffirmation of the borrowing base at $260.0 million. The next scheduled redetermination is set to occur in May 2021.

The Credit Facility is guaranteed by all wholly-owned subsidiaries of the Company (each, a “Guarantor” and, together with the Company, the “Credit Parties”), and is secured by first priority security interests on substantially all assets of each Credit Party, subject to customary exceptions.

Under the original terms of the Credit Facility, borrowings bore interest at a per annum rate equal to, at the option of the Company, either (i) a London InterBank Offered Rate (“LIBOR”), subject to a 0% LIBOR floor plus a margin of 1.75% to 2.75%, based on the utilization of the Credit Facility (the “Eurodollar Rate”) or (ii) a fluctuating interest rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan Chase Bank, N.A. as its prime rate, (b) the rate of interest published by the Federal Reserve Bank of New York as the federal funds effective rate, (c) the rate of interest published by the Federal Reserve Bank of New York as the overnight bank funding rate, or (d) a LIBOR offered rate for a one month interest period, subject to a 0% LIBOR floor plus a margin of 0.75% to 1.75%, based on the utilization of the Credit Facility (the “Reference Rate”). Interest on borrowings that bear interest at the Eurodollar Rate shall be payable on the last day of the applicable interest period selected by the Company, which shall be one, two, three, or six months, and interest on borrowings that bear interest at the Reference Rate shall be payable quarterly in arrears.

The Credit Facility contains customary representations and affirmative covenants. The Credit Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) liens, (ii) indebtedness, guarantees and other obligations, (iii) restrictions in agreements on liens and distributions, (iv) mergers or consolidations, (v) asset sales, (vi) restricted payments, (vii) investments, (viii) affiliate transactions, (ix) change of business, (x) foreign operations or subsidiaries, (xi) name changes, (xii) use of proceeds, letters of credit, (xiii) gas imbalances, (xiv) hedging transactions, (xv) additional subsidiaries, (xvi) changes in fiscal year or fiscal quarter, (xvii) operating leases, (xviii) prepayments of certain debt and other obligations, (xix) sales or discounts of receivables, and (xx) dividend payments. The Credit Parties are subject to certain financial covenants under the Credit Facility, as tested on the last day of each fiscal quarter, including, without limitation, (i) a maximum ratio of the Company’s consolidated indebtedness (subject to certain exclusions) to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash charges (“EBITDAX”) and (ii) a current ratio, as defined in the agreement, inclusive of the unused Commitments then available to be borrowed, to not be less than 1.00 to 1.00.

On June 18, 2020, in conjunction with the borrowing base redetermination, the Company, together with certain of its subsidiaries, entered into the First Amendment (the “First Amendment”) to the Credit Facility (as amended, restated, supplemented or otherwise modified) to, among other things: (i) implement certain anti-cash hoarding provisions, including a weekly mandatory prepayment requirement with respect to the excess of the Company's consolidated cash balance over $35.0 million; (ii) require that, in order to borrow or issue a letter of credit under the Credit Agreement, the consolidated cash balance not exceed the greater of $35.0 million (both before and after giving effect to such borrowing or letter of credit issuance), or expenditures in respect of oil and gas properties in the ordinary course of business (as agreed to by the administrative agent); (iii) decrease the maximum permitted net leverage ratio from 4.00 to 3.50 and the maximum permitted leverage ratio for purposes of making a restricted payment, restricted investment or optional or voluntary redemption from 3.25 to 2.75; (iv) increase the Eurodollar Rate margin to 2.00% to 3.00%; (v) increase the Reference Rate margin to 1.00% to 2.00%; and (vi) amend certain other covenants and provisions.

The Company was in compliance with all covenants as of December 31, 2020 and through the filing date of this report.

Our weighted-average interest rates on borrowings from the Credit Facility were 3.1% and 4.4% for the years ended December 31, 2020 and 2019, respectively. As of December 31, 2020 and as of the date of filing, we had a zero balance on our Credit Facility.

**Non-GAAP Financial Measures**

Adjusted EBITDAX represents earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash and non-recurring charges. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Facility based on adjusted EBITDAX ratios as further described above in *Liquidity and Capital Resources*. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies.

The following table presents a reconciliation of the GAAP financial measure of net income to the non-GAAP financial measure of Adjusted EBITDAX (in thousands):

| | Year Ended December 31, 2020 | Year Ended December 31, 2019 |
|---|---|---|
| Net income | $ 103,528 | $ 67,067 |
| Exploration | 596 | 797 |
| Depreciation, depletion, and amortization | 91,242 | 76,453 |
| Amortization of deferred financing costs | — | 248 |
| Abandonment and impairment of unproved properties | 37,343 | 11,201 |
| Stock-based Compensation[1] | 6,156 | 6,886 |
| Severance costs[1] | 1,337 | 751 |
| Merger transaction costs | 6,676 | — |
| (Gain) loss on property transactions, net | 1,398 | (1,177) |
| Interest expense, net | 2,045 | 2,650 |
| Severance and ad valorem taxes adjustment[2] | (16,291) | — |
| Derivative (gain) loss | (53,462) | 37,145 |
| Derivative cash settlements | 49,406 | 1,691 |
| Income tax benefit | (60,547) | — |
| Adjusted EBITDAX | $ 169,427 | $ 203,712 |

[1] Included as a portion of general and administrative expense in the accompanying consolidated statements of operations and comprehensive income ("statements of operations").

[2] Included as a portion of severance and ad valorem taxes in the accompanying statements of operations.

**Critical Accounting Policies and Estimates**

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates, and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

*Method of accounting for oil and natural gas properties*

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

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

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

Unproved properties are supported by probable and possible well locations and cost incurred to acquire unproved leases. Unproved lease costs are capitalized until the leases expire or when probable and possible well locations are reassessed and entire areas are no longer represented, at which time we expense the associated unproved lease costs. The expensing or expiration of unproved lease costs are recorded as abandonment or impairment of unproved properties in the statements of operations and comprehensive income (loss) in our consolidated financial statements. Lease costs are reclassified to proved properties and depleted on a unit-of-production basis once proved reserves have been assigned.

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

*Oil and natural gas reserve quantities and Standardized Measure*

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

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

*Revenue Recognition*

Sales of oil, natural gas, and NGLs are recognized when performance obligations are satisfied at the point control of the product is transferred to the customer. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies. Please refer to *Part II, Item* 8, *Note 1 - Summary of Significant Accounting Policies* for more information.

We record revenue in the month production is delivered to the purchaser. Payment is generally received within 30 to 60 days after the date of production. However, settlement statements for certain natural gas and NGLs sales may not be received for 30 to 60 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received for product sales in the month in which payment is received from the purchaser. For the period from January 1, 2020 through December 31, 2020, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Company has interests with other producers in certain properties, in which case the Company uses the entitlement method to account for gas imbalances. The Company had no material gas imbalances as of December 31, 2020 and 2019.

*Impairment of proved properties*

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

*Impairment of unproved properties*

The unproved property balance at emergence from bankruptcy represents probable and possible well locations that are reassessed at least annually. The assessment of probable and possible locations incorporates key factors such as economic viability, surface constraints, wells per section, limitations on operatorship due to working interest changes, and any relevant components at such time. Changes in probable and possible locations that result in entire areas no longer being represented in the reserve run are impaired.

Leases acquired post-emergence are assessed for impairment applying the following factors:

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

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

*Asset retirement obligations*

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

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

*Derivatives*

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

*Stock-based compensation*

*Restricted Stock Units.* We recognize compensation expense for all restricted stock units granted to employees and directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as an expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Stock-based compensation expense recorded for restricted stock units is included in general and administrative expenses on our accompanying statements of operations.

*Performance Stock Units.* We recognize compensation expense for all performance stock unit awards granted to employees. The number of shares of the Company's common stock that may be issued to settle PSUs ranges from zero to two times the number of PSUs awarded. The PSUs vest in their entirety at the end of the three-year performance period. The total number of PSUs granted is split between two performance criteria. The first criterion is based on a comparison of the Company's absolute and relative total shareholder return ("TSR") for the performance period compared with the TSRs of a group of peer companies for the same performance period. The TSR for the Company and each of the peer companies is determined by dividing (A) (i) the volume-weighted average share price for the last 30 trading days of the performance period minus (ii) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period, by (B) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period. The second criterion is based on the Company's annual return on average capital employed ("ROCE") for each year during the three-year performance period. The split between the two performance criteria is even for the PSUs granted in 2018 and 2019, whereas the split is two-thirds weighted to the TSR criterion and one-third weighted to the ROCE criterion for the PSUs granted in 2020. Compensation expense associated with PSUs is recognized as general and administrative expense over the performance period. Because these awards depend on a combination of performance-based and market-based settlement criteria, compensation expense may be adjusted in future periods as the number of units expected to vest increases or decreases based on the Company's expected ROCE performance.

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

*Stock Options.* We recognize compensation expense for all stock option awards granted to employees. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as an expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of stock option grants is based on a Black-Scholes Model. Stock-based compensation expense recorded for stock option awards is included in general and administrative expenses on our accompanying statements of operations.

*Income taxes*

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

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

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. We did not have any uncertain tax positions as of the year ended December 31, 2020.

*Recent accounting pronouncements*

Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* for additional details.

**Effects of Inflation and Pricing**

Inflation in the United States was 1.6% in 2020, 2.3% in 2019, and 2.2% in 2018. These changes did not have a material impact on our results of operations for the periods ended December 31, 2020, 2019, and 2018. Although the impact of inflation has been relatively insignificant in recent years, it is still a factor in the United States economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations, depletion expense, impairment assessments of oil and gas properties, ARO, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money, and retain personnel.

**Off-Balance Sheet Arrangements**

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

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

**Oil and Natural Gas Price Risk**

Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil and natural gas, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels, local and global politics, and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations, and capital resources. If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 2% and our PV-10 value as of December 31, 2020 would decrease by approximately 27% or $117.6 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 1% and our PV-10 value as of December 31, 2020 would increase by approximately 27% or $119.3 million.

PV-10 is a non-GAAP financial measure. Please refer to *Estimated Proved Reserves* under Part I, Item 1 of this Annual Report on Form 10-K for management's discussion of this non-GAAP financial measure.

*Commodity Derivative Contracts*

Our primary commodity risk management objective is to protect the Company's balance sheet via the reduction in cash flow volatility. We enter into derivative contracts for oil, natural gas, and natural gas liquids using NYMEX futures or over-the-counter derivative financial instruments. The types of derivative instruments that we use include swaps, collars, and puts.

Upon settlement of the contract(s), if the relevant market commodity price exceeds our contracted swap price, or the collar's ceiling strike price, we are required to pay our counterparty the difference for the volume of production associated with the contract. Generally, this payment is made up to 15 business days prior to the receipt of cash payments from our customers. This could have an adverse impact on our cash flows for the period between derivative settlements and payments for revenue earned.

While we may reduce the potential negative impact of lower commodity prices, we may also be prevented from realizing the benefits of favorable price changes in the physical market.

Presently, our derivative contracts have been executed with seven counterparties, all of which are members of our Credit Facility syndicate. We enter into contracts with counterparties whom we believe are well capitalized. However, if our counterparties fail to perform their obligations under the contracts, we could suffer financial loss.

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

For the oil and natural gas derivatives outstanding at December 31, 2020, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2020 would decrease our derivative gain by $14.2 million or increase it by $13.0 million, respectively.

*Interest Rates*

At both December 31, 2020 and on the filing date of this report, we had a zero balance on our Credit Facility. Borrowings under our Credit Facility bear interest at a fluctuating rate that is tied to an adjusted Base Rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flows. As of December 31, 2020 and through the filing date of this report, the Company was in compliance with all financial and non-financial covenants.

*Counterparty and Customer Credit Risk*

In connection with our derivatives activity, we have exposure to financial institutions in the form of derivative transactions. Seven lenders under our Credit Facility are counterparties on our derivative instruments currently in place and have investment grade credit ratings.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history, and financial resources of our customers, but we do not require our customers to post collateral.

*Marketability of Our Production*

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

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

Currently, there are no pipeline systems that service wells in our French Lake area of the Wattenberg Field. If neither we nor a third-party constructs the required pipeline system, we may not be able to fully test or develop our resources in French Lake.

**Item 8.** ***Financial Statements and Supplementary Data.***

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Bonanza Creek Energy, Inc.

### Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Bonanza Creek Energy, Inc. and subsidiaries (the "Company") as of December 31, 2020 and 2019, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows, for each of the two years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 17, 2021, expressed an unqualified opinion on the Company's internal control over financial reporting.

### Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

### Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

***Proved Oil and Gas Properties and Depletion — Estimated Proved Reserves — Refer to Note 1 to the consolidated financial statements***

*Critical Audit Matter Description*

The Company's capitalized costs of proved oil and gas properties are depleted using the units of production method based on estimated proved reserves, and such costs are evaluated for impairment by comparison of the carrying value of the assets to the undiscounted future net cash flows of the underlying estimated proved reserves. The development of the Company's estimated proved reserves and the related undiscounted future net cash flows requires management to make significant estimates and assumptions related to the Company's ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking and future oil and natural gas prices. The Company engages an independent reserve engineer to estimate oil and natural gas quantities using these estimates and assumptions and engineering data. Changes in these assumptions could materially affect the estimated quantities of the Company's reserves. The proved oil and gas properties, net balance was $845 million, as of December 31, 2020. Depletion expense was $82.6 million for the year ended December 31, 2020. No proved oil and gas property impairment was recognized during the year ended December 31, 2020.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's estimated proved reserves and the related undiscounted future net cash flows including management's estimates and assumptions related to (1) converting proved undeveloped reserves to producing properties within five years and (2) future oil and natural gas prices required a high degree of auditor judgment and an increased extent of effort.

*How the Critical Audit Matter Was Addressed in the Audit*

Our audit procedures related to management's significant judgments and assumptions related to converting proved undeveloped reserves to producing properties within five years and future oil and natural prices included the following, among others:

- We tested the operating effectiveness of controls related to the Company's estimation of proved reserves, including controls relating to the five-year conversion plan and future oil and natural gas prices.
- We evaluated the reasonableness of management's five-year conversion plan by comparing the forecasts to:
  - Historical conversions of proved undeveloped oil and gas reserves into proved developed oil and gas reserves.
  - The Company's drill plan and the availability of capital relative to the drill plan.
  - Internal communications to management and the Board of Directors.
  - Permits and approval for expenditures.
  - Forecasted information for the Denver-Julesburg basin included in Company press releases as well as in analyst and industry reports for the Company and certain of its peer companies.
- We evaluated management's estimated future oil and natural gas prices by:
  - Understanding the methodology used by management for development of the future prices and comparing the estimated prices to an independently determined range of estimated future prices.
  - Comparing management's estimates to published forward pricing indices and third-party industry sources.
  - Comparing the price differentials incorporated in the future oil and natural gas prices to historical realized price differentials.
- We evaluated the experience, qualifications and objectivity of management's expert, an independent reserve engineering firm.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 17, 2021

We have served as the Company's auditor since 2019.

## Report of Independent Registered Accounting Firm

Board of Directors and Stockholders
Bonanza Creek Energy, Inc.

**Opinion on the financial statements**
We have audited the accompanying consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows of Bonanza Creek Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") for the year ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the results of its operations and its cash flows for the year ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

**Basis for opinion**
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We served as the Company's auditor from 2017 to 2019.

Oklahoma City, Oklahoma
February 27, 2019

**BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS**
**(in thousands, except per share amounts)**

| | As of December 31, 2020 | As of December 31, 2019 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 24,743 | $ 11,008 |
| Accounts receivable, net: | | |
| Oil and gas sales | 32,673 | 43,714 |
| Joint interest and other | 14,748 | 38,136 |
| Prepaid expenses and other | 3,574 | 7,048 |
| Inventory of oilfield equipment | 9,185 | 7,726 |
| Derivative assets (note 12) | 7,482 | 2,884 |
| Total current assets | 92,405 | 110,516 |
| Property and equipment (successful efforts method): | | |
| Proved oil and gas properties | 1,056,773 | 935,025 |
| Less: accumulated depreciation, depletion, and amortization | (211,432) | (126,614) |
| Total proved oil and gas properties, net | 845,341 | 808,411 |
| Unproved properties | 98,122 | 143,020 |
| Wells in progress | 50,609 | 98,750 |
| Other property and equipment, net of accumulated depreciation of $3,737 in 2020 and $3,142 in 2019 | 3,239 | 3,394 |
| Total property and equipment, net | 997,311 | 1,053,575 |
| Long-term derivative assets (note 12) | — | 121 |
| Right-of-use assets (note 2) | 29,705 | 38,562 |
| Deferred income tax assets (note 9) | 60,520 | — |
| Other noncurrent assets (note 4) | 2,871 | 3,544 |
| Total assets | $ 1,182,812 | $ 1,206,318 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable and accrued expenses (note 5) | $ 37,425 | $ 57,638 |
| Oil and gas revenue distribution payable | 18,613 | 29,021 |
| Lease liability (note 2) | 12,044 | 11,690 |
| Derivative liability (note 12) | 6,402 | 6,390 |
| Total current liabilities | 74,484 | 104,739 |
| Long-term liabilities: | | |
| Credit facility (note 6) | — | 80,000 |
| Lease liability (note 2) | 17,978 | 27,540 |
| Ad valorem taxes | 15,069 | 28,520 |
| Derivative liability (note 12) | 1,330 | 921 |
| Asset retirement obligations for oil and gas properties (note 10) | 28,699 | 27,908 |
| Total liabilities | 137,560 | 269,628 |
| Commitments and contingencies (note 7) | | |
| Stockholders' equity: | | |
| Preferred stock, $.01 par value, 25,000,000 shares authorized, none outstanding | — | — |
| Common stock, $.01 par value, 225,000,000 shares authorized, 20,839,227 and 20,643,738 issued and outstanding as of December 31, 2020 and 2019, respectively | 4,282 | 4,284 |
| Additional paid-in capital | 707,209 | 702,173 |
| Retained earnings | 333,761 | 230,233 |
| Total stockholders' equity | 1,045,252 | 936,690 |
| Total liabilities and stockholders' equity | $ 1,182,812 | $ 1,206,318 |

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

**BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**
**(in thousands, except per share amounts)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Operating net revenues: | | | |
| Oil and gas sales | $ 218,090 | $ 313,220 | $ 276,657 |
| Operating expenses: | | | |
| Lease operating expense | 21,957 | 25,249 | 34,825 |
| Gas plant and midstream operating expense | 14,948 | 12,014 | 10,788 |
| Gathering, transportation, and processing | 16,932 | 16,682 | 9,732 |
| Severance and ad valorem taxes | 3,787 | 25,598 | 18,999 |
| Exploration | 596 | 797 | 291 |
| Depreciation, depletion, and amortization | 91,242 | 76,453 | 41,883 |
| Abandonment and impairment of unproved properties | 37,343 | 11,201 | 5,271 |
| Unused commitments | — | — | 21 |
| Bad debt expense | 818 | — | — |
| Merger transaction costs | 6,676 | — | — |
| General and administrative expense (including $6,156, $6,886, and $7,156, respectively, of stock-based compensation) | 34,936 | 39,668 | 42,453 |
| Total operating expenses | 229,235 | 207,662 | 164,263 |
| Other income (expense): | | | |
| Derivative gain (loss) | 53,462 | (37,145) | 30,271 |
| Interest expense, net | (2,045) | (2,650) | (2,603) |
| Gain (loss) on property transactions, net | (1,398) | 1,177 | 27,324 |
| Other income | 4,107 | 127 | 800 |
| Total other income (expense) | 54,126 | (38,491) | 55,792 |
| Income before income taxes | 42,981 | 67,067 | 168,186 |
| Income tax benefit | 60,547 | — | — |
| Net income | $ 103,528 | $ 67,067 | $ 168,186 |
| | | | |
| Comprehensive income | $ 103,528 | $ 67,067 | $ 168,186 |
| | | | |
| Net income per common share: | | | |
| Basic | $ 4.98 | $ 3.25 | $ 8.20 |
| Diluted | $ 4.95 | $ 3.24 | $ 8.16 |
| Weighted-average common shares outstanding | | | |
| Basic | 20,774 | 20,612 | 20,507 |
| Diluted | 20,912 | 20,681 | 20,603 |

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

# BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
**(in thousands, except per share amounts)**

| | Common Stock | | Additional Paid-In Capital | Accumulated Earnings (Deficit) | Total |
|---|---|---|---|---|---|
| | Shares | Amount | | | |
| **Balances, January 1, 2018** | 20,453,549 | $ 4,286 | $ 689,068 | $ (5,020) | $ 688,334 |
| Restricted common stock issued | 84,345 | — | — | — | — |
| Restricted stock used for tax withholdings | (25,991) | — | (863) | — | (863) |
| Exercise of stock options | 32,037 | — | 1,100 | — | 1,100 |
| Stock-based compensation | — | — | 7,156 | — | 7,156 |
| Net income | — | — | — | 168,186 | 168,186 |
| **Balances, December 31, 2018** | 20,543,940 | 4,286 | 696,461 | 163,166 | 863,913 |
| Restricted common stock issued | 146,359 | — | — | — | — |
| Restricted stock used for tax withholdings | (46,561) | (2) | (1,174) | — | (1,176) |
| Stock-based compensation | — | — | 6,886 | — | 6,886 |
| Net income | — | — | — | 67,067 | 67,067 |
| **Balances, December 31, 2019** | 20,643,738 | 4,284 | 702,173 | 230,233 | 936,690 |
| Restricted common stock issued | 259,995 | — | — | — | — |
| Restricted stock used for tax withholdings | (64,506) | (2) | (1,120) | — | (1,122) |
| Stock-based compensation | — | — | 6,156 | — | 6,156 |
| Net income | — | — | — | 103,528 | 103,528 |
| **Balances, December 31, 2020** | 20,839,227 | $ 4,282 | $ 707,209 | $ 333,761 | $ 1,045,252 |

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

**BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in thousands)**

| | Year Ended December 31, 2020 | 2019 | 2018 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net income | $ 103,528 | $ 67,067 | $ 168,186 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion, and amortization | 91,242 | 76,453 | 41,883 |
| Deferred income tax benefit | (60,520) | — | — |
| Abandonment and impairment of unproved properties | 37,343 | 11,201 | 5,271 |
| Well abandonment costs and dry hole expense | (8) | 172 | — |
| Stock-based compensation | 6,156 | 6,886 | 7,156 |
| Non-cash lease component | (249) | 668 | — |
| Amortization of deferred financing costs | 864 | 487 | 30 |
| Derivative (gain) loss | (53,462) | 37,145 | (30,271) |
| Derivative cash settlements | 49,406 | 1,691 | (18,160) |
| (Gain) loss on property transactions, net | 1,398 | (1,177) | (27,324) |
| Other | 71 | 3,559 | (3,311) |
| Changes in current assets and liabilities: | | | |
| Accounts receivable, net | 24,945 | (2,688) | (46,988) |
| Prepaid expenses and other assets | 3,352 | (2,415) | 2,214 |
| Accounts payable and accrued liabilities | (41,278) | 28,320 | 19,953 |
| Settlement of asset retirement obligations | (3,992) | (2,722) | (2,041) |
| Net cash provided by operating activities | 158,796 | 224,647 | 116,598 |
| Cash flows from investing activities: | | | |
| Acquisition of oil and gas properties | (3,210) | (14,087) | (2,892) |
| Exploration and development of oil and gas properties | (60,149) | (242,487) | (264,231) |
| Proceeds from sale of oil and gas properties | — | 1,757 | 103,134 |
| Additions to property and equipment - non oil and gas | (440) | (341) | (387) |
| Net cash used in investing activities | (63,799) | (255,158) | (164,376) |
| Cash flows from financing activities: | | | |
| Proceeds from credit facility | 45,000 | 55,000 | 140,000 |
| Payments to credit facility | (125,000) | (25,000) | (90,000) |
| Proceeds from exercise of stock options | — | — | 1,100 |
| Payment of employee tax withholdings in exchange for the return of common stock | (1,122) | (1,176) | (863) |
| Deferred financing costs | (23) | (220) | (2,239) |
| Principal payments on finance lease obligations | (102) | — | — |
| Net cash provided by (used in) financing activities | (81,247) | 28,604 | 47,998 |
| Net change in cash, cash equivalents, and restricted cash | 13,750 | (1,907) | 220 |
| Cash, cash equivalents, and restricted cash: | | | |
| Beginning of period | 11,095 | 13,002 | 12,782 |
| End of period | $ 24,845 | $ 11,095 | $ 13,002 |
| Supplemental cash flow disclosure[(1)]: | | | |
| Cash paid for interest, net of capitalization | $ 1,546 | $ 4,110 | $ 2,582 |
| Severance and ad valorem tax refund | $ — | $ 352 | $ — |
| Receivables exchanged for additional interests in oil and gas properties | $ 8,299 | $ — | $ — |
| Changes in working capital related to drilling expenditures | $ 2,795 | $ 30,354 | $ 11,769 |

(1) Refer to *Note 2 - Leases* in the notes to the consolidated financial statements for discussion of right-of-use assets obtained in exchange for lease liabilities.

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

**BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES**
**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS**

## NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

*Description of Operations*

Bonanza Creek Energy, Inc. (“BCEI” or, together with its consolidated subsidiaries, the “Company”) is engaged primarily in acquiring, developing, extracting, and producing oil and gas properties. The Company’s assets and operations are concentrated in the rural portions of the Wattenberg Field in Colorado.

*Basis of Presentation*

As of December 31, 2020, the consolidated balance sheets (“balance sheets”) include the accounts of the Company and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Holmes Eastern Company, LLC, and Rocky Mountain Infrastructure, LLC. All intercompany accounts and transactions have been eliminated. Certain prior period amounts have been reclassified to conform to the current period presentation. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2020, through the filing date of this report.

On August 6, 2018, the Company sold its equity interests in Bonanza Creek Energy Resources, LLC, which owned all of the outstanding equity interest in Bonanza Creek Energy Upstream LLC and Bonanza Creek Energy Midstream, LLC. These subsidiaries comprised the Company's Mid-Continent region and assets. Please refer to *Note 3 - Acquisitions & Divestitures* for additional discussion.

*Use of Estimates*

The preparation of the Company's consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. These estimates and other factors, including those outside of the Company's control, such as the impact of lower commodity prices, may impact the Company's business, financial condition, results of operations, and cash flows.

*Going Concern Presumption*

Our consolidated financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets, and the satisfaction of liabilities and other commitments in the normal course of business.

*Industry Segment and Geographic Information*

The Company operates in one industry segment, which is the development and production of oil, natural gas, and NGLs, and all of the Company's operations are conducted in the continental United States. Consequently, the Company currently reports as a single industry segment.

*Cash and Cash Equivalents*

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

*Accounts Receivable*

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

*Inventory of Oilfield Equipment*

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

*Oil and Gas Producing Activities*

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

Depletion of proved oil and gas properties is computed using the units-of-production method based on produced volumes and estimated proved reserves. The computation of depletion takes into consideration restoration, dismantlement, and abandonment costs and anticipated proceeds from salvaging equipment. Because all of our oil and gas properties are currently located in a single field, we apply depletion on a single field basis. During the years ended December 31, 2020, 2019, and 2018, the Company incurred $82.6 million, $69.3 million, and $34.6 million, respectively, in depletion expense.

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

The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering, and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, differentials, revenues, taxes, capital expenditures, operating expenses, and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, our ability to fund estimated development cost, prevailing oil and gas prices, and other factors, many of which are beyond our control.

As of December 31, 2020, the net book value of the Company's gathering assets was $153.0 million in the accompanying balance sheets. Depreciation on the Company's gathering assets is calculated using the straight-line method over the estimated useful lives of the assets and the assets it is servicing, which is approximately 30 years.

Unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis once proved reserves have been assigned. The unproved property balance at emergence from bankruptcy represents probable and possible well locations that are reassessed at least annually. The assessment of probable and possible locations incorporates key factors such as economic viability, surface constraints, wells per section, limitations on operatorship due to working interest changes, and any relevant components at such time. Changes in probable and possible locations that result in entire areas no longer being represented in the reserve run are impaired. Leases acquired post-emergence are assessed for impairment applying the following factors:

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

During the years ended December 31, 2020, 2019, and 2018, the Company incurred $37.3 million, $11.2 million, and $5.3 million, respectively, in abandonment and impairment of unproved properties due to the reassessment of estimated probable and possible reserve locations based primarily upon economic viability and the expiration of non-core leases.

The Company records the fair value of an asset retirement obligation as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. The increase in carrying value is included in proved properties in the accompanying balance sheets. For additional discussion, please refer to *Note 10 - Asset Retirement Obligations.*

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

*Other Property and Equipment*

Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Cost of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed as incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to 25 years.

*Assets Held for Sale*

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. Any subsequent decreases to the estimated fair value less the costs to sell impact the measurement of assets held for sale. Any properties deemed held for sale as of the balance sheet date are presented separately on the accompanying balance sheets at the lower of net book value or fair value less cost to sell. Please refer to *Note 3 - Acquisitions & Divestitures* for more information.

*Revenue Recognition*

Sales of oil, natural gas, and NGLs are recognized when performance obligations are satisfied at the point control of the product is transferred to the customer. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil, natural gas, and NGLs fluctuates to remain competitive with other available oil, natural gas, and NGLs supplies.

As further described in *Note 7 - Commitments and Contingencies*, one contract with NGL Crude has an additional aspect of variable consideration related to the minimum volume commitments ("MVCs") as specified in the agreement. On an on-going basis, the Company performs an analysis of expected risk adjusted production applicable to the NGL Crude agreement based on approved production plans to determine if liquidated damages to NGL Crude are probable. As of December 31, 2020, the Company believes that the volumes delivered to NGL Crude will be in excess of the MVCs required then and for the upcoming approved production plan. As a result of this analysis, to date, no variable consideration related to potential liquidated damages has been considered in the transaction price for the NGL Crude agreement.

Under the oil sales contracts, the Company sells oil production at the wellhead, or other contractually agreed-upon delivery points, and collects an agreed-upon index price, net of pricing differentials. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the wellhead, or other contractually agreed-upon delivery point, at the net contracted price received.

Under the natural gas processing contracts, the Company delivers natural gas to an agreed-upon delivery point. The delivery points are specified within each contract, and the transfer of control varies between the inlet and outlet of the midstream processing facility. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs and residue gas. For the contracts where the Company maintains control through the outlet of the midstream processing facility, the Company recognizes revenue on a gross basis, with gathering, transportation, and processing fees presented as an expense in the Company's accompanying statements of operations. Alternatively, for those contracts where the Company relinquishes control at the inlet of the midstream processing facility, the Company recognizes natural gas and NGLs revenues based on the contracted amount of the proceeds received from the midstream processing entity and, as a result, the Company recognizes revenue on a net basis.

Under the product sales contracts, the Company invoices customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under this guidance. At December 31, 2020 and 2019, the Company's receivables from contracts with customers were $32.7 million and $43.7 million, respectively. Payment is generally received within 30 to 60 days after the date of production.

The Company records revenue in the month production is delivered to the purchaser. However, as stated above, settlement statements for certain natural gas and NGLs sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between its estimates and the actual amounts received for product sales in the month in which payment is received from the purchaser. For the period from January 1, 2020 through December 31, 2020, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was insignificant.

Revenue attributable to each identified revenue stream is disaggregated below (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| Operating revenues: | | | |
| Crude oil sales | $ 174,536 | $ 268,865 | $ 228,661 |
| Natural gas sales | 24,243 | 28,296 | 22,369 |
| Natural gas liquids sales | 19,311 | 16,059 | 25,627 |
| Oil and gas sales | $ 218,090 | $ 313,220 | $ 276,657 |

*Income Taxes*

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

*Uncertain Tax Positions*

The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The tax returns for 2019, 2018, and 2017 are still subject to audit by the Internal Revenue Service. There were no uncertain tax positions during any period presented.

*Concentrations of Credit Risk*

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

The Company is exposed to credit risk in the event of nonpayment by counterparties whose creditworthiness is continuously evaluated. For the years ended December 31, 2020, 2019, and 2018, NGL Crude Logistics accounted for 77%, 82%, and 66% of sales, respectively, and Duke Energy Field Services accounted for 9%, 6%, and 8% of sales, respectively.

*Oil and Gas Derivative Activities*

The Company is exposed to commodity price risk related to oil and gas prices. To mitigate this risk, the Company enters into oil and gas derivative contracts. The contracts are placed with major financial institutions and take the form of swaps, collars, or puts. The oil contracts are indexed to NYMEX WTI prices, and natural gas contracts are indexed to NYMEX HH and CIG prices, which have a high degree of historical correlation with actual prices received by the Company, before differentials. The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value. For additional discussion, please refer to *Note 12 - Derivatives*.

*Earnings Per Share*

Earnings per basic and diluted share are calculated under the treasury stock method. Basic net income (loss) per common share is calculated by dividing net income (loss) by the basic weighted-average common shares outstanding for the respective period. Diluted net income (loss) per common share is calculated by dividing net income (loss) by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested restricted stock units (“RSUs”), in-the-money outstanding stock options, unvested performance stock units (“PSUs”), and exercisable warrants. When the Company recognizes a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted earnings per share. For additional discussion, please refer to *Note 13 - Earnings Per Share*.

*Stock-Based Compensation*

The Company measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. For additional discussion, please refer to *Note 8 - Stock-Based Compensation*.

*Fair Value of Financial Instruments*

The Company’s financial instruments consist of cash and cash equivalents, trade receivables, trade payables, accrued liabilities, credit facilities, and derivative instruments. Cash and cash equivalents, trade receivables, trade payables, and accrued liabilities are carried at cost and approximate fair value due to the short-term nature of these instruments. Our credit facilities have variable interest rates, so they approximate fair value. Derivative instruments are recorded at fair value.

*Restricted Cash*

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets, which sums to the total of such amounts shown in the accompanying consolidated statements of cash flows (in thousands):

| | As of December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Cash and cash equivalents | $ 24,743 | $ 11,008 | $ 12,916 |
| Restricted cash[(1)] | 102 | 87 | 86 |
| Total cash, cash equivalents, and restricted cash | $ 24,845 | $ 11,095 | $ 13,002 |

(1) Included in other noncurrent assets and consists of funds for road maintenance and repairs.

*Recently Issued and Adopted Accounting Standards*

In June 2016, the FASB issued *Update No. 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The update changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. The amended standard was adopted using a modified retrospective approach on January 1, 2020. The Company considered past events (including historical experience), current economic and industry conditions, reasonable and supportable forecasts, and lives of receivable balances and loss experience. Historically and currently, the Company's credit losses on oil and natural gas sales receivables and joint interest receivables have not been significant, and the adoption of this standard did not have a material impact on its consolidated financial statements. As of December 31, 2020, the Company has an allowance of $0.4 million established against joint interest receivables.

In August 2018, the FASB issued *Update No. 2018-13, Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*. The objective of this update is to improve the effectiveness of fair value measurement disclosures. The new standard was adopted on January 1, 2020. The standard only impacted the form of the Company's disclosures.

In March 2020, the FASB issued *Update No. 2020-04, Reference Rate Reform (Topic 848),* which provides temporary optional guidance to companies impacted by the transition away from the LIBOR. The amendment provides certain expedients and exceptions to applying GAAP in order to lessen the potential accounting burden when contracts, hedging relationships, and other transactions that reference LIBOR as a benchmark rate are modified. Further, in January 2021, the FASB issued *Update No. 2021-01, Reference Rate Reform (Topic 848),* which clarifies the scope of Topic 848 so that derivatives affected by the discounting transition are explicitly eligible for certain optional expedients and exceptions in Topic 848. These amendments are effective upon issuance and expire on December 31, 2022. The Company is currently assessing the impact of the LIBOR transition on the Company's consolidated financial statements.

There are no other accounting standards applicable to the Company that would have a material effect on the Company’s financial statements and disclosures that have been issued but not yet adopted by the Company as of December 31, 2020, and through the filing date of this report.

**NOTE 2 - LEASES**

The Company’s right-of-use assets and lease liabilities are recognized at their discounted present value on the balance sheet, which include leases related to the asset classes reflected as of the dates indicated in the table below (in thousands):

| | December 31, | |
|---|---|---|
| | 2020 | 2019 |
| **Operating Leases** | | |
| Field equipment(1) | $ 27,537 | $ 35,057 |
| Corporate leases | 1,481 | 2,462 |
| Vehicles | 468 | 1,043 |
| Total right-of-use asset | $ 29,486 | $ 38,562 |
| | | |
| Field equipment(1) | $ 27,537 | $ 35,075 |
| Corporate leases | 1,900 | 3,129 |
| Vehicles | 468 | 1,026 |
| Total lease liability | $ 29,905 | $ 39,230 |
| | | |
| **Finance Leases** | | |
| Right of use asset - field equipment(1) | $ 219 | $ — |
| Lease liability - field equipment(1) | $ 117 | $ — |

(1) Includes compressors, certain gas processing equipment, and other field equipment.

The lease amounts disclosed are presented on a gross basis. A portion of these costs may have been or will be billed to other working interest owners, and the Company's net share of these costs, once paid, are included in various line items on the statements of operations or capitalized to oil and gas properties or other property and equipment, as applicable.

The Company recognizes operating lease expense on a straight-line basis. Finance lease expense is recognized based on the effective interest method for the lease liability and straight-line amortization for the right-of-use asset, resulting in more cost being recognized in earlier lease periods. Short-term and variable lease payments are recognized as incurred. Short-term lease cost represents payments for leases with a lease term of one year or less, excluding leases with a term of one month or less. Short-term leases include drilling rigs and other equipment. Drilling rig contracts are structured based on an allotted number of wells to be drilled consecutively at a daily operating rate. Short-term drilling rig costs include a non-lease labor component, which is treated as a single lease component.

The following table summarizes the components of the Company's gross lease costs incurred during the years ended December 31, 2020 and 2019 (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Operating lease cost[1] | $ 13,957 | $ 11,330 |
| Finance lease cost | | |
| Amortization of ROU assets | 18 | — |
| Interest on lease liabilities | 5 | — |
| Short-term lease cost | 2,058 | 8,169 |
| Variable lease cost[2] | (186) | 259 |
| Sublease income[3] | (358) | (348) |
| Total lease cost | $ 15,494 | $ 19,410 |

(1) Includes office rent expense of $1.1 million for each of the years ended December 31, 2020 and 2019.
(2) Variable lease cost represents differences between lease obligations and actual costs incurred for certain leases that do not have fixed payments related to both lease and non-lease components. Such incremental costs include lease payment increases or decreases driven by market price fluctuations and leased asset maintenance costs.
(3) The Company has subleased a portion of its office space for the remainder of the office lease term.

The Company does not have any leases with an implicit interest rate that can be readily determined. As a result, the Company used the incremental borrowing rate, based on the Credit Facility benchmark rate, adjusted for facility utilization and lease term, to calculate the respective discount rates. Please refer to *Note 6 - Long-term Debt* for additional information.

The Company has certain lease agreements that provide for the option to extend, purchase, or terminate early, which was evaluated on each lease to arrive at the proper lease term. There were some leases for which the option to extend or purchase was factored into the resulting lease term. There were no leases where early termination was factored into the resulting lease term. The Company's weighted-average remaining lease terms and discount rates as of December 31, 2020 are as follows:

| | Operating Leases | Finance Leases |
|---|---|---|
| Weighted-average lease term (years) | 2.8 | 0.2 |
| Weighted-average discount rate | 3.90% | 3.47% |

Supplemental cash flow information related to leases for the years ended December 31, 2020 and 2019 consisted of the following (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Cash paid for amounts included in the measurement of lease liabilities: | | |
| Operating cash flows from operating leases | $ 12,768 | $ 10,993 |
| Operating cash flows from finance leases | 5 | — |
| Financing cash flows from finance leases | 102 | — |
| | | |
| Right-of-use assets obtained in exchange for new operating lease obligations | $ 8,306 | $ 16,568 |
| Right-of-use assets obtained in exchange for new finance lease obligations | 219 | — |

Future commitments by year for the Company's operating and finance leases with a lease term of one year or more as of December 31, 2020 are presented in the table below. Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the balance sheet as follows (in thousands):

| | Operating Leases | Finance Leases |
|---|---|---|
| 2021 | $ 12,836 | $ 118 |
| 2022 | 9,788 | — |
| 2023 | 6,371 | — |
| 2024 | 2,439 | — |
| 2025 | 108 | — |
| Thereafter | — | — |
| Total lease payments | 31,542 | 118 |
| Less: imputed interest | (1,637) | (1) |
| Total lease liability | $ 29,905 | $ 117 |

**NOTE 3 - ACQUISITIONS & DIVESTITURES**

On November 9, 2020, the Company and HighPoint Resources Corporation entered into a Merger Agreement, providing for the Company's acquisition of HighPoint. The preliminary merger consideration is expected to be $337.4 million, consisting of a combination of the issuance of shares of the Company's common stock and senior notes. Upon execution of the Merger Agreement, HighPoint paid BCEI $6.0 million in consideration for, among other things, the costs and expenses to be incurred by the Company to pursue consummation of this acquisition. The transaction is expected to close in the first half of 2021, contingent upon a number of factors disclosed in the Merger Agreement.

In August 2018, the Company entered into an agreement to simultaneously close and divest of all of its assets within its Mid-Continent region. Net proceeds, including 2019 purchase price adjustments, amounted to $103.5 million resulting in a gain of approximately $28.6 million, included in the gain (loss) on property transactions, net line item in the accompanying statements of operations.

In March 2018, the Company sold its North Park Basin assets for minimal net proceeds and full release of all current and future obligations resulting in a minimal net loss.

**NOTE 4 - OTHER NONCURRENT ASSETS**

Other noncurrent assets contain the following (in thousands):

| | As of December 31, 2020 | As of December 31, 2019 |
|---|---|---|
| Operating bonds | $ 1,641 | $ 1,638 |
| Deferred financing costs | 725 | 1,443 |
| AMT credit refund[(1)] | 403 | 376 |
| Restricted cash | 102 | 87 |
| Other noncurrent assets | $ 2,871 | $ 3,544 |

(1) Represents the alternative minimum tax credit refund due to the Company upon application of the enacted comprehensive tax legislation that took effect on December 22, 2017.

## NOTE 5 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses contain the following (in thousands):

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Accrued drilling and completion costs | $ 453 | $ 3,248 |
| Accounts payable trade | 1,931 | 17,117 |
| Accrued general and administrative expense | 7,529 | 5,620 |
| Accrued lease operating expense | 1,793 | 2,187 |
| Accrued interest expense | 322 | 692 |
| Accrued oil and gas hedging | — | 453 |
| Accrued production and ad valorem taxes and other | 25,397 | 28,321 |
| Total accounts payable and accrued expenses | $ 37,425 | $ 57,638 |

## NOTE 6 - LONG-TERM DEBT

*Credit Facility*

In December 2018, the Company entered into a reserve-based revolving facility, as the borrower, with JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions, as lenders. The $750.0 million Credit Facility has a maturity date of December 7, 2023 and was governed by an initial borrowing base of $350.0 million. The Credit Facility borrowing base is redetermined on a semi-annual basis. In June 2020, the borrowing base and aggregate elected commitments were reduced to $260.0 million. The most recent redetermination was concluded on December 18, 2020, resulting in a reaffirmation of the borrowing base at $260.0 million. The next scheduled redetermination is set to occur in May 2021.

The Credit Facility is guaranteed by all wholly owned subsidiaries of the Company and is secured by first priority security interests on substantially all assets of each Credit Party, subject to customary exceptions.

Under the original terms of the Credit Facility, borrowings bore interest at a per annum rate equal to, at the option of the Company, either (i) a LIBOR, subject to a 0% LIBOR floor plus a margin of 1.75% to 2.75%, based on the utilization of the Credit Facility (the Eurodollar Rate) or (ii) a fluctuating interest rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan Chase Bank, N.A. as its prime rate, (b) the rate of interest published by the Federal Reserve Bank of New York as the federal funds effective rate, (c) the rate of interest published by the Federal Reserve Bank of New York as the overnight bank funding rate, or (d) a LIBOR offered rate for a one month interest period, subject to a 0% LIBOR floor plus a margin of 0.75% to 1.75%, based on the utilization of the Credit Facility (the Reference Rate). Interest on borrowings that bear interest at the Eurodollar Rate shall be payable on the last day of the applicable interest period selected by the Company, which shall be one, two, three, or six months, and interest on borrowings that bear interest at the Reference Rate shall be payable quarterly in arrears.

The Credit Facility contains customary representations and affirmative covenants. The Credit Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) liens, (ii) indebtedness, guarantees and other obligations, (iii) restrictions in agreements on liens and distributions, (iv) mergers or consolidations, (v) asset sales, (vi) restricted payments, (vii) investments, (viii) affiliate transactions, (ix) change of business, (x) foreign operations or subsidiaries, (xi) name changes, (xii) use of proceeds, letters of credit, (xiii) gas imbalances, (xiv) hedging transactions, (xv) additional subsidiaries, (xvi) changes in fiscal year or fiscal quarter, (xvii) operating leases, (xviii) prepayments of certain debt and other obligations, (xix) sales or discounts of receivables, and (xx) dividend payments. The Credit Parties are subject to certain financial covenants under the Credit Facility, as tested on the last day of each fiscal quarter, including, without limitation, (i) a maximum ratio of the Company’s consolidated indebtedness (subject to certain exclusions) to EBITDAX and (ii) a current ratio, as defined in the agreement, inclusive of the unused Commitments then available to be borrowed, to not be less than 1.00 to 1.00.

On June 18, 2020, in conjunction with the borrowing base redetermination, the Company, together with certain of its subsidiaries, entered into the First Amendment to the Credit Facility (as amended, restated, supplemented or otherwise modified) to, among other things: (i) implement certain anti-cash hoarding provisions, including a weekly mandatory prepayment requirement with respect to the excess of the Company's consolidated cash balance over $35.0 million; (ii) require that, in order to borrow or issue a letter of credit under the Credit Agreement, the consolidated cash balance not exceed the greater of $35.0 million (both before and after giving effect to such borrowing or letter of credit issuance), or expenditures in respect of oil and gas properties in the ordinary course of business (as agreed to by the administrative agent); (iii) decrease the maximum permitted net leverage ratio from 4.00 to 3.50 and the maximum permitted leverage ratio for purposes of making a restricted payment, restricted investment or optional or voluntary redemption from 3.25 to 2.75; (iv) increase the Eurodollar Rate margin to 2.00% to 3.00%; (v) increase the Reference Rate margin to 1.00% to 2.00%; and (vi) amend certain other covenants and provisions. The Company was in compliance with all covenants as of December 31, 2020 and through the filing date of this report.

The Company had zero and $80.0 million outstanding on the Credit Facility as of December 31, 2020 and 2019, respectively. As of the date of this filing, the outstanding balance was zero. The Company's Credit Facility approximates fair value as the applicable interest rates are floating.

In connection with the Credit Facility, the Company capitalized a total of $2.5 million in deferred financing costs. Of the total post-amortization net capitalized amounts, (i) $0.7 million and $1.4 million as of December 31, 2020 and 2019, respectively, are presented within other noncurrent assets and (ii) $0.4 million and $0.5 million as of December 31, 2020 and 2019, respectively, are presented within prepaid expenses and other line items in the accompanying balance sheets.

*Prior Credit Facility*

In April 2017, the Company entered into a revolving credit facility, as the borrower, with KeyBank National Association, as the administrative agent, and certain lenders party thereto (the “Prior Credit Facility”). The borrowing base was $191.7 million and had a maturity date of March 31, 2021.

The Prior Credit Facility provided for interest rates plus an applicable margin to be determined based on LIBOR or a base rate, at the Company’s election. LIBOR borrowings bore interest at LIBOR, plus a margin of 3.00% to 4.00% depending on the utilization level, and the base rate borrowings bore interest at the Reference Rate, as defined in the Prior Credit Facility, plus a margin of 2.00% to 3.00% depending on the utilization level.

This Prior Credit Facility was terminated and settled in full as of December 7, 2018.

**Interest Expense**

For the years ended December 31, 2020, 2019, and 2018, the Company incurred interest expense of $3.8 million, $5.1 million, and $2.6 million respectively. The Company capitalized $1.8 million and $2.4 million of interest expense during the years ended December 31, 2020 and 2019. No interest was capitalized for the year ended December 31, 2018.

**NOTE 7 - COMMITMENTS AND CONTINGENCIES**

*Legal Proceedings*

From time to time, the Company is involved in various commercial and regulatory claims, litigation, and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. In accordance with authoritative accounting guidance, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the most likely anticipated outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. No claims have been made, nor is the Company aware of any material uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations. As of the filing date of this report, there were no probable, material pending, or overtly threatened legal actions against the Company of which it was aware.

In September 2018, the Company reached a settlement in a case in which it was one of several plaintiffs seeking reimbursement of ad valorem taxes that were assessed by a special metropolitan district in Colorado. Pursuant to that settlement, the Company received a gross reimbursement of ad valorem taxes paid in the amount of $7.4 million. The settlement amount of $5.1 million, net of the Company's associated interest owners' portion, is presented as a reimbursement in the accompanying statements of operations within the severance and ad valorem taxes line item.

*Commitments*

The Company is party to a purchase agreement to deliver fixed determinable quantities of crude oil to NGL Crude. The NGL Crude agreement includes defined volume commitments over a term ending in 2023. Under the terms of the NGL Crude agreement, the Company is required to make periodic deficiency payments for any shortfalls in delivering minimum gross volume commitments, which are set in six-month periods. The minimum gross volume commitment will increase approximately 3% each year for the remainder of the contract, to a maximum of approximately 16,000 gross barrels per day. The aggregate financial commitment fee over the remaining term is $49.7 million as of December 31, 2020. Upon notifying NGL Crude at least twelve months prior to the expiration date of the NGL Crude agreement, the Company may elect to extend the term of the NGL Crude agreement for up to three additional years.

The annual minimum commitment payments under the NGL Crude agreement for the next five years as of December 31, 2020 are presented below (in thousands):

| | NGL Crude Commitments[1] |
|---|---|
| 2021 | $ 22,403 |
| 2022 | 23,097 |
| 2023 | 4,201 |
| 2024 | — |
| 2025 and thereafter | — |
| Total | $ 49,701 |

(1) The above calculation is based on the minimum volume commitment schedule (as defined in the NGL Crude agreement) and applicable differential fees.

Since the commencement of the NGL Crude agreement and through the remainder of the term of the agreement, the Company has not and does not expect to incur any deficiency payments. Refer to *Note 2 - Leases* for lease commitments.

## NOTE 8 - STOCK-BASED COMPENSATION

*Long Term Incentive Plan*

In 2017, the Company adopted a Long Term Incentive Plan (the "LTIP"), as established by the Board, which allows for the issuance of RSUs, PSUs, and options, and reserved 2,467,430 shares of common stock. See below for further discussion of awards granted under the LTIP.

The Company recorded compensation expense related to the awards granted under the LTIP as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Restricted stock units | $ 5,283 | $ 5,518 | $ 5,140 |
| Performance stock units | 748 | 764 | 621 |
| Stock options | 125 | 604 | 1,395 |
| Total stock-based compensation | $ 6,156 | $ 6,886 | $ 7,156 |

As of December 31, 2020, unrecognized compensation expense will be amortized through the relevant periods as follows (in thousands):

| | Unrecognized Compensation Expense | Final Year of Recognition |
|---|---|---|
| Restricted stock units | $ 7,789 | 2023 |
| Performance stock units | 1,946 | 2022 |
| Total unrecognized stock-based compensation | $ 9,735 | |

*Inducement Awards*

During the year ended December 31, 2018, the Company granted inducement awards in the form of RSUs separate and distinct from the LTIP. The total number of inducement awards granted to employees during the year ended December 31, 2018 was 170,613, representing a total fair value of $4.6 million.

*Restricted Stock Units*

The LTIP allows for the issuance of RSUs to members of the Board and employees of the Company at the discretion of the Board. Each RSU represents one share of the Company's common stock to be released from restriction upon completion of the vesting period. The awards typically vest in one-third increments over three years. The RSUs are valued at the grant date share price and are recognized as general and administrative expense over the vesting period of the award.

The fair value of the RSUs granted from the LTIP during the years ended December 31, 2020, 2019, and 2018 was $4.9 million, $5.9 million, and $6.2 million, respectively.

A summary of the status and activity of non-vested restricted stock units for the year ended December 31, 2020 is presented below:

| | Restricted Stock Units | Weighted-Average Grant-Date Fair Value |
|---|---|---|
| Non-vested, beginning of year | 557,817 | $ 26.95 |
| Granted | 306,945 | 15.90 |
| Vested | (259,995) | 15.74 |
| Forfeited | (54,711) | 24.77 |
| Non-vested, end of year | 550,056 | $ 20.30 |

Cash flows resulting from excess tax benefits are to be classified as part of cash flows from operating activities. Excess tax benefits are realized tax benefits from tax deductions for vested restricted stock in excess of the deferred tax asset attributable to stock compensation costs for such restricted stock. The Company recorded no excess tax benefits for the periods presented.

*Performance Stock Units*

The LTIP allows for the issuance of PSUs to employees at the sole discretion of the Board. The number of shares of the Company’s common stock that may be issued to settle PSUs ranges from zero to two times the number of PSUs awarded. The PSUs vest in their entirety at the end of the three-year performance period. The total number of PSUs granted is split between two performance criteria. The first criterion is based on a comparison of the Company’s absolute and relative total shareholder return (“TSR”) for the performance period compared with the TSRs of a group of peer companies for the same performance period. The TSR for the Company and each of the peer companies is determined by dividing (A) (i) the volume-weighted average share price for the last 30 trading days of the performance period, minus (ii) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period, by (B) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period. The second criterion is based on the Company's annual return on average capital employed (“ROCE”) for each year during the three-year performance period. The split between the two performance criteria was even for the PSUs granted in 2018 and 2019, whereas the split was two-thirds weighted to the TSR criterion and one-third weighted to the ROCE criterion for the PSUs granted in 2020. Compensation expense associated with PSUs is recognized as general and administrative expense over the performance period. Because these awards depend on a combination of performance-based and market-based settlement criteria, compensation expense may be adjusted in future periods as the number of units expected to vest increases or decreases based on the Company’s expected ROCE performance. As of December 31, 2020, the Company knew and does not expect any of the ROCE portion of the PSUs granted in 2018 and 2019 to vest, respectively, and has accordingly adjusted the related compensation expense.

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

The following table presents the assumptions used to determine the fair value of the TSR portion of the PSUs:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Expected term (in years) | 3 | 3 | 3 |
| Risk-free interest rate | 0.22 % | 2.26 % | 2.76 % |
| Expected daily volatility | 3.5 % | 2.6 % | 2.6 % |

The fair value of the PSUs granted during 2020, 2019, and 2018 was \$1.9 million, \$2.3 million, and \$1.8 million, respectively. The PSUs granted in 2018 expired as of December 31, 2020, with zero distribution of shares to the recipients, as neither the TSR nor the ROCE performance criteria were met.

A summary of the status and activity of performance stock units for the year ended December 31, 2020 is presented below:

| | Performance Stock Units[1] | Weighted-Average Grant-Date Fair Value |
|---|---|---|
| Non-vested, beginning of year | 153,470 | $ 24.74 |
| Granted | 83,209 | 23.22 |
| Vested | — | — |
| Forfeited | — | — |
| Expired | (51,091) | 29.92 |
| Non-vested, end of year | 185,588 | $ 22.63 |

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

*Stock Options*

The LTIP allows for the issuance of stock options to the Company's employees at the sole discretion of the Board. Options expire ten years from the grant date unless otherwise determined by the Board. Compensation expense on the stock options is recognized as general and administrative expense over the vesting period of the award. There were no stock options granted during 2020, 2019, and 2018.

Stock options are valued using a Black-Scholes Model where expected volatility is based on an average historical volatility of a peer group selected by management over a period consistent with the expected life assumption on the grant date, the risk-free rate of return is based on the U.S. Treasury constant maturity yield on the grant date with a remaining term equal to the expected term of the awards, and the Company's expected life of stock option awards is derived from the midpoint of the average vesting time and contractual term of the awards.

A summary of the status and activity of non-vested stock options for the year ended December 31, 2020 is presented below:

| | Stock Options | Weighted-Average Exercise Price | Weighted-Average Remaining Contractual Term (in years) | Aggregate Intrinsic Value (in thousands) |
|---|---|---|---|---|
| Outstanding, beginning of year | 100,714 | $ 34.36 | | |
| Granted | — | — | | |
| Exercised | — | — | | |
| Forfeited | (28,346) | 34.36 | | |
| Outstanding, end of year | 72,368 | $ 34.36 | 6.3 | $ — |
| Options outstanding and exercisable | 72,368 | $ 34.36 | 6.3 | $ — |

## NOTE 9 - INCOME TAXES

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

The provision for income taxes consists of the following (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Current tax expense | | | |
| Federal | $ (27) | $ — | $ — |
| State | — | — | — |
| Total current tax expense | (27) | — | — |
| Deferred tax benefit | | | |
| Federal | (53,784) | — | — |
| State | (6,736) | — | — |
| Total deferred tax benefit | (60,520) | — | — |
| Total income tax benefit | $ (60,547) | $ — | $ — |

Temporary differences between the financial statement carrying amounts and tax basis of assets and liabilities that give rise to the net deferred tax asset result from the following components (in thousands):

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Deferred tax liabilities: | | |
| Oil and gas properties | $ 89,867 | $ 79,187 |
| Right-of-use assets | 7,306 | 9,508 |
| Total deferred tax liabilities | 97,173 | 88,695 |
| Deferred tax assets: | | |
| Federal and state tax net operating loss carryforward | 138,372 | 139,546 |
| Derivative instruments | 61 | 1,062 |
| Reclamation costs | 7,058 | 6,881 |
| Stock compensation | 1,653 | 2,209 |
| Inventory | 1,598 | 1,577 |
| Lease liability | 7,384 | 9,673 |
| Pending acquisition costs | 1,478 | — |
| Other long-term assets | 89 | 300 |
| Total deferred tax assets | 157,693 | 161,248 |
| Less: Valuation allowance | — | 72,553 |
| Total deferred tax assets after valuation allowance | 157,693 | 88,695 |
| Total non-current net deferred tax asset | $ 60,520 | $ — |

The Company has $579.4 million and $582.8 million of net operating loss carryovers for federal income tax purposes as of December 31, 2020 and 2019, respectively. Federal net operating loss carryforwards incurred prior to January 1, 2018 of $465.7 million will begin to expire in 2036. Federal net operating loss carryforwards incurred after December 31, 2017 of $113.7 million have no expiration and can only be used to offset 80% of taxable income when utilized.

The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will be realized. In making such determination, the Company considers all available (both positive and negative) evidence, including future reversals of temporary differences, tax-planning strategies, projected future taxable income, and results of operations. The Company has cumulative book income for the prior three years and is forecasting future book income, which resulted in the full valuation allowance of $72.6 million, that was recorded against the Company's deferred tax asset as of December 31, 2019, to be removed. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that the deferred tax assets will be realized.

Federal income tax expense differs from the amount that would be provided by applying the statutory United States federal income tax rate of 21% to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, rate changes, and other permanent differences, as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Federal statutory tax expense | $ 9,026 | $ 14,084 | $ 35,319 |
| Increase (decrease) in tax resulting from: | | | |
| State tax expense net of federal benefit | 1,694 | 2,537 | 6,556 |
| Prior year true-up | 292 | (579) | (458) |
| Stock compensation | 690 | 197 | 854 |
| Permanent differences | 36 | 128 | 61 |
| State rate change | 124 | — | (421) |
| NOL Adjustment | — | — | 5,973 |
| Section 162(m) limitation | 144 | 156 | — |
| Valuation allowance | (72,553) | (16,523) | (47,884) |
| Total income tax benefit | $ (60,547) | $ — | $ — |

During the year ended December 31, 2020, the decrease in tax rate was primarily due to fully removing the valuation allowance against net deferred tax assets and net income decreasing between the comparable periods. There was $60.5 million of deferred income tax benefit in the accompanying statements of operations. The valuation allowance decreased by $72.6 million to zero in 2020 when compared to the same period in 2019 due to both current and forecasted book income.

During the year ended December 31, 2019, there were no deferred income tax benefits or expense in the accompanying statements of operations. The valuation allowance decreased by $16.5 million to $72.6 million in 2019 when compared to the same period in 2018. The Company's net income decreased between the comparable periods causing the federal tax benefit to decrease.

During the year ended December 31, 2018, the decrease in tax rate was primarily due to placing a valuation allowance against net deferred tax assets. There was no deferred income tax benefits or expense in the accompanying statements of operations. The valuation allowance decreased to $89.1 million in 2018 due to improvement of operational results. Net operating losses are inherently subject to changes in ownership. The net operating loss adjustment was derived from the write-off of the Company's Mid-Continent tax attributes upon the sale of those assets.

The Company had no unrecognized tax benefits as of December 31, 2020, 2019, and 2018. The tax returns for 2019, 2018, and 2017 are still subject to audit by the Internal Revenue Service.

**NOTE 10 - ASSET RETIREMENT OBLIGATIONS**

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

The Company's estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimated costs to abandon the wells, and regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred.

A roll-forward of the Company's asset retirement obligation is as follows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Balance, beginning of year | $ 27,908 | $ 29,405 |
| Additional liabilities incurred | 357 | 228 |
| Accretion expense | 1,004 | 1,467 |
| Liabilities settled | (2,464) | (2,443) |
| Revisions to estimate | 1,894 | (749) |
| Balance, end of year | $ 28,699 | $ 27,908 |

Revisions to estimates for the year ended December 31, 2020 were primarily a result of increased abandonment costs and decreased estimated economic well lives. Revisions to estimates for the year ended December 31, 2019 were primarily a result of decreased abandonment costs.

**NOTE 11 - FAIR VALUE MEASUREMENTS**

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

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

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

Level 3: Significant inputs to the valuation model are unobservable

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

*Derivatives*

Fair value of all derivative instruments are estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. All valuations were compared against counterparty statements to verify the reasonableness of the estimate. The Company's commodity swaps, collars, and puts were validated by observable transactions for the same or similar commodity options using the NYMEX futures index and were designated as Level 2 within the valuation hierarchy. The following tables present the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2020 and 2019 and their classification within the fair value hierarchy (in thousands):

| | As of December 31, 2020 | | |
|---|---|---|---|
| | Level 1 | Level 2 | Level 3 |
| Derivative assets | $ — | $ 7,482 | $ — |
| Derivative liabilities | $ — | $ 7,732 | $ — |

| | As of December 31, 2019 | | |
|---|---|---|---|
| | Level 1 | Level 2 | Level 3 |
| Derivative assets | $ — | $ 3,005 | $ — |
| Derivative liabilities | $ — | $ 7,311 | $ — |

*Proved Oil and Gas Properties*

Proved oil and gas property costs are evaluated for impairment on a nonrecurring basis and reduced to fair value when there is an indication that the carrying costs exceed the sum of the undiscounted cash flows of the underlying oil and gas reserves. Depending on the availability of data, the Company uses Level 3 inputs and either the income valuation technique, which converts future amounts to a single present value amount to measure the fair value of proved properties through an application of risk-adjusted discount rates and price forecasts selected by the Company's management, or the market valuation approach. The calculation of the risk-adjusted discount rate is a significant management estimate based on the best information available. Management believes that the risk-adjusted discount rate is representative of current market conditions and reflects the following factors: estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on the Company's internal budgeting model derived from the NYMEX strip pricing, adjusted for management estimates and basis differentials. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If a relevant estimated selling price is not available, the Company utilizes the income valuation technique discussed above. There were no proved oil and gas property impairments during the years ended December 31, 2020 and 2019.

**NOTE 12 - DERIVATIVES**

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

In a typical commodity swap agreement, if the agreed upon published third-party index price is lower than the swap strike price, the Company receives the difference between the index price and the agreed upon swap strike price. If the index price is higher than the swap strike price, the Company pays the difference.

A put gives the owner the right to sell the underlying commodity at a set price over the term of the contract. If the index settlement price is higher than the put fixed price, the put will expire worthless. If the settlement price is lower than the put fixed price, the Company will exercise the put and receive the difference between the settlement price and the put fixed price.

A cashless collar arrangement establishes a floor and ceiling price on future oil and gas production. When the settlement price is above the ceiling price, the Company pays the difference between the settlement price and the ceiling price.

When the settlement price is below the floor price, the Company receives the difference between the settlement price and floor price. In the event that the settlement price is between the ceiling and the floor, no payment or receipt occurs.

A basis swap arrangement guarantees a price differential from a specified delivery point to an agreed upon reference point. The Company receives the difference between the price differential and the stated terms, if the price differential is greater than the stated terms. The Company pays the difference between the price differential and the stated terms, if the stated terms are greater than the price differential.

As of December 31, 2020, the Company had entered into the following commodity derivative contracts:

| | Crude Oil (NYMEX WTI) | | Natural Gas (NYMEX Henry Hub) | | Natural Gas (CIG Basis) | | Natural Gas (CIG) | |
|---|---|---|---|---|---|---|---|---|
| | Bbls/day | Weighted Avg. Price per Bbl | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu |
| **1Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $43.67/$53.58 | 30,000 | $2.25/$2.57 | — | — | — | — |
| Swap | 5,000 | $54.48 | — | — | 20,000 | $0.43 | — | — |
| **2Q21** | | | | | | | | |
| Cashless Collar | 2,500 | $34.40/$49.82 | 20,000 | $2.25/$2.52 | — | — | — | — |
| Swap | 4,000 | $54.13 | — | — | 20,000 | $0.43 | — | — |
| **3Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $30.00/$50.62 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 2,500 | $54.45 | — | — | 20,000 | $0.43 | — | — |
| **4Q21** | | | | | | | | |
| Cashless Collar | 4,000 | $30.63/$50.34 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 1,000 | $55.20 | — | — | 20,000 | $0.43 | — | — |
| **1Q22** | | | | | | | | |
| Cashless Collar | 3,500 | $31.43/$51.00 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **2Q22** | | | | | | | | |
| Cashless Collar | 2,000 | $32.50/$54.85 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **3Q22** | | | | | | | | |
| Cashless Collar | 1,000 | $35.00/$54.88 | — | — | — | — | — | — |
| **4Q22** | | | | | | | | |
| Cashless Collar | 500 | $35.00/$55.00 | — | — | — | — | — | — |

As of the filing date of this report, the Company had entered into the following commodity derivative contracts:

| | Crude Oil (NYMEX WTI) | | Natural Gas (NYMEX Henry Hub) | | Natural Gas (CIG Basis) | | Natural Gas (CIG) | |
|---|---|---|---|---|---|---|---|---|
| | Bbls/day | Weighted Avg. Price per Bbl | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu | MMBtu/day | Weighted Avg. Price per MMBtu |
| **1Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $43.67/$53.58 | 30,000 | $2.25/$2.57 | — | — | — | — |
| Swap | 5,000 | $54.48 | — | — | 20,000 | $0.43 | — | — |
| **2Q21** | | | | | | | | |
| Cashless Collar | 2,500 | $34.40/$49.82 | 20,000 | $2.25/$2.52 | — | — | — | — |
| Swap | 4,000 | $54.13 | — | — | 20,000 | $0.43 | — | — |
| **3Q21** | | | | | | | | |
| Cashless Collar | 3,000 | $30.00/$50.62 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 2,500 | $54.45 | — | — | 20,000 | $0.43 | — | — |
| **4Q21** | | | | | | | | |
| Cashless Collar | 4,000 | $30.63/$50.34 | 20,000 | $2.25/$2.52 | — | — | 20,000 | $2.15/$2.75 |
| Swap | 1,000 | $55.20 | — | — | 20,000 | $0.43 | — | — |
| **1Q22** | | | | | | | | |
| Cashless Collar | 4,000 | $31.88/$51.83 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **2Q22** | | | | | | | | |
| Cashless Collar | 2,500 | $33.00/$55.41 | — | — | — | — | 20,000 | $2.15/$2.75 |
| **3Q22** | | | | | | | | |
| Cashless Collar | 1,000 | $35.00/$54.88 | — | — | — | — | — | — |
| **4Q22** | | | | | | | | |
| Cashless Collar | 500 | $35.00/$55.00 | — | — | — | — | — | — |

*Derivative Assets and Liabilities Fair Value*

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The following table contains a summary of all the Company's derivative positions reported on the accompanying balance sheets as of December 31, 2020 and 2019 (in thousands):

| | As of December 31, | |
|---|---|---|
| | **2020** | **2019** |
| *Derivative Assets:* | | |
| Commodity contracts - current | $ 7,482 | $ 2,884 |
| Commodity contracts - noncurrent | — | 121 |
| *Derivative Liabilities:* | | |
| Commodity contracts - current | (6,402) | (6,390) |
| Commodity contracts - long-term | (1,330) | (921) |
| Total derivative liabilities, net | $ (250) | $ (4,306) |

The following table summarizes the components of the derivative gain (loss) presented on the accompanying statements of operations for the periods below (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| Derivative cash settlement gain (loss): | | | |
| Oil contracts | $ 50,133 | $ 1,185 | $ (17,700) |
| Gas contracts | (727) | 506 | (460) |
| Total derivative cash settlement gain (loss)[(1)] | 49,406 | 1,691 | (18,160) |
| Change in fair value gain (loss) | 4,056 | (38,836) | 48,431 |
| Total derivative gain (loss)[(1)] | $ 53,462 | $ (37,145) | $ 30,271 |

______________________

(1) Total derivative gain (loss) and total derivative cash settlement gain (loss) for each of the periods presented above is reported in the derivative (gain) loss line item and derivative cash settlements line item in the accompanying statements of cash flows, within the cash flows from operating activities.

**NOTE 13 - EARNINGS PER SHARE**

The Company issues RSUs, which represent the right to receive, upon vesting, one share of the Company's common stock. The number of potentially dilutive shares related to RSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the vesting period. The Company issues PSUs, which represent the right to receive, upon settlement of the PSUs, a number of shares of the Company's common stock that ranges from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the performance period applicable to such PSUs. The Company issued stock options and warrants, which both represent the right to purchase the Company's common stock at a specified price. The number of potentially dilutive shares related to the stock options and warrants is based on the number of shares, if any, that would be exercisable at the end of the respective reporting period, assuming the date was the end of such stock options' or warrants' term.

Please refer to *Note 8 - Stock-Based Compensation* for additional discussion.

The Company uses the treasury stock method to calculate earnings per share as shown in the following table (in thousands, except per share amounts):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Net income | $ 103,528 | $ 67,067 | $ 168,186 |
| | | | |
| Basic net income per common share | $ 4.98 | $ 3.25 | $ 8.20 |
| Diluted net income per common share | $ 4.95 | $ 3.24 | $ 8.16 |
| | | | |
| Weighted-average shares outstanding - basic | 20,774 | 20,612 | 20,507 |
| Add: dilutive effect of contingent stock awards | 138 | 69 | 96 |
| Weighted-average shares outstanding - diluted | 20,912 | 20,681 | 20,603 |

There were 248,744, 269,208, and 170,755 shares that were anti-dilutive for the years ended December 31, 2020, 2019, and 2018 respectively. The exercise price of the Company's warrants was in excess of the Company's stock price; therefore, they were excluded from the earnings per share calculation. The Company's warrants expired on April 30, 2020.

**NOTE 14 - DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)**

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Acquisition(1) | $ 11,296 | $ 12,901 | $ 2,861 |
| Development(2)(3) | 55,934 | 209,535 | 304,197 |
| Exploration | 595 | 796 | 294 |
| Total | $ 67,825 | $ 223,232 | $ 307,352 |

(1) Acquisition costs for unproved properties for the years ended December 31, 2020, 2019, and 2018 were $2.3 million, $4.2 million, and $2.5 million, respectively. There were $9.0 million, $8.7 million, and $0.4 million in acquisition costs for proved properties for the years ended December 31, 2020, 2019, and 2018, respectively.
(2) Development costs include workover costs of $1.2 million, $1.4 million, and $5.6 million charged to lease operating expense for the years ended December 31, 2020, 2019, and 2018, respectively.
(3) Includes amounts relating to asset retirement obligations of $(1.0) million, $(0.9) million, and $(9.0) million, for the years ended December 31, 2020, 2019, and 2018, respectively.

***Suspended Well Costs***

The Company did not incur any exploratory well costs during the years ended December 31, 2020, 2019, and 2018.

***Reserves***

The proved reserve estimates were prepared by our third party independent reserve engineers, which were Ryder Scott at December 31, 2020 and NSAI for the estimates at December 31, 2019 and 2018. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

All of the Company’s oil, natural gas liquids, and natural gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil, natural gas liquids, and natural gas reserves for the years ended December 31, 2020, 2019, and 2018 are as follows:

| | Oil (MBbl) | Natural Gas (MMcf) | Natural Gas Liquids (MBbl) |
|---|---|---|---|
| Balance-December 31, 2017 | 52,928 | 157,669 | 22,815 |
| Extensions, discoveries and infills[1] | 18,390 | 31,471 | 5,197 |
| Production | (3,841) | (8,567) | (1,140) |
| Sales of minerals in place | (6,236) | (20,534) | (1,499) |
| Removed from capital program[2] | (1,442) | (3,246) | (544) |
| Revisions to previous estimates[3] | 4,555 | 8,219 | 101 |
| Balance-December 31, 2018 | 64,354 | 165,012 | 24,930 |
| Extensions, discoveries and infills[1] | 8,825 | 20,604 | 3,123 |
| Production | (5,136) | (11,967) | (1,431) |
| Sales of minerals in place | (52) | (110) | (18) |
| Removed from capital program[2] | (4,926) | (11,508) | (1,862) |
| Purchases of minerals in place | 303 | 627 | 102 |
| Revisions to previous estimates[3] | 1,045 | 49,542 | (2,683) |
| Balance-December 31, 2019 | 64,413 | 212,200 | 22,161 |
| Extensions, discoveries and infills[1] | 9,376 | 32,172 | 3,269 |
| Production | (5,019) | (14,166) | (1,858) |
| Sales of minerals in place | — | — | — |
| Removed from capital program[2] | (14,120) | (33,886) | (3,141) |
| Purchases of minerals in place | 1,430 | 5,457 | 570 |
| Revisions to previous estimates[3] | (3,287) | 33,951 | 5,110 |
| Balance-December 31, 2020 | 52,793 | 235,728 | 26,111 |
| | | | |
| Proved developed reserves: | | | |
| December 31, 2018 | 23,725 | 79,630 | 11,703 |
| December 31, 2019 | 25,397 | 105,840 | 11,566 |
| December 31, 2020 | 24,320 | 123,220 | 14,315 |
| Proved undeveloped reserves: | | | |
| December 31, 2018 | 40,629 | 85,382 | 13,227 |
| December 31, 2019 | 39,016 | 106,360 | 10,595 |
| December 31, 2020 | 28,473 | 112,508 | 11,796 |

(1) During the years ended December 31, 2020, 2019, and 2018, horizontal development in the Wattenberg Field resulted in additions in extensions, discoveries, and infills of 18.0 MMBoe, 15.4 MMBoe, and 28.8 MMBoe, respectively.

(2) During the years ended December 31, 2020, 2019, and 2018, proved undeveloped reserves were reduced by 22.9 MMBoe, 8.7 MMBoe, and 2.5 MMBoe respectively, primarily due to the removal of proved undeveloped locations from our five-year drilling program.

(3) As of December 31, 2020, the Company revised its proved reserves upward by 7.5 MMBoe primarily driven by 12.3 MMBoe in positive engineering revisions. The commodity prices at December 31, 2020 decreased to $39.57 per Bbl WTI and $1.99 per MMBtu HH from $55.85 per Bbl WTI and $2.58 per MMBtu HH at December 31, 2019, resulting in a partially offsetting negative revision of 4.8 MMBoe.

As of December 31, 2019, the Company revised its proved reserves upward by 6.6 MMBoe. The commodity prices at December 31, 2019 decreased to $55.85 per Bbl WTI and $2.58 per MMBtu HH from $65.56 per Bbl WTI and $3.10 per MMBtu HH at December 31, 2018, resulting in a negative revision of 1.4 MMBoe, offset by 8.1 MMBoe in positive engineering revision.

As of December 31, 2018, the Company revised its proved reserves upward by 6.0 MMBoe. The commodity prices at December 31, 2018 increased to $65.56 per Bbl WTI and $3.10 per MMBtu HH from $51.34 per Bbl WTI and $2.98 per MMBtu HH at December 31, 2017, resulting in positive revisions of 2.3 MMBoe. In addition, lower operating cost estimates resulted in positive reserve adjustments of 1.5 MMBoe. There were net positive engineering revisions of 2.2 MMBoe.

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

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

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Future cash flows | $ 2,230,012 | $ 3,827,009 | $ 4,742,180 |
| Future production costs | (675,755) | (1,029,140) | (1,585,032) |
| Future development costs | (530,970) | (850,327) | (925,640) |
| Future income tax expense | — | — | — |
| Future net cash flows | 1,023,287 | 1,947,542 | 2,231,508 |
| 10% annual discount for estimated timing of cash flows | (586,233) | (1,089,395) | (1,276,528) |
| Standardized measure of discounted future net cash flows | $ 437,054 | $ 858,147 | $ 954,980 |

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

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Beginning of period | $ 858,147 | $ 954,980 | $ 598,498 |
| Sale of oil and gas produced, net of production costs | (160,466) | (233,677) | (204,566) |
| Net changes in prices and production costs | (641,137) | (372,233) | 365,952 |
| Net changes in extensions, discoveries and improved recoveries | (54,269) | 45,728 | 153,691 |
| Development costs incurred | 42,325 | 185,086 | 127,788 |
| Changes in estimated development cost | 220,964 | 81,358 | (52,260) |
| Purchases of minerals in place | 12,372 | 10,135 | — |
| Sales of minerals in place | — | (309) | (115,742) |
| Revisions of previous quantity estimates | 60,754 | 79,637 | 12,341 |
| Net change in income taxes | — | — | — |
| Accretion of discount | 85,815 | 95,498 | 59,850 |
| Changes in production rates and other | 12,549 | 11,944 | 9,428 |
| End of period | $ 437,054 | $ 858,147 | $ 954,980 |

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2020, 2019, and 2018 were calculated using the twelve-month arithmetic average of first-day-of-the-month prices inclusive of adjustments for quality and location.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Oil (per Bbl) | $ 34.96 | $ 51.22 | $ 59.29 |
| Gas (per Mcf) | $ 0.95 | $ 1.44 | $ 2.28 |
| Natural gas liquids (per Bbl) | $ 6.12 | $ 10.07 | $ 22.06 |

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

As disclosed in our Current Report on Form 8-K, filed on June 19, 2019, we engaged Deloitte & Touche LLP (“Deloitte”) as the Company’s new independent registered public accounting firm to audit the Company’s financial statements starting with the fiscal year ending December 31, 2019, and dismissed Grant Thornton LLP (“Grant Thornton”) as the Company’s independent registered accounting firm. The decision to change the Company’s independent registered accounting firm from Grant Thornton to Deloitte was approved by the Audit Committee of the Board.

During the fiscal year ended December 31, 2018 and through June 19, 2019, there were no disagreements with Grant Thornton on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedures, that if not resolved to the satisfaction of Grant Thornton, would have caused Grant Thornton to make reference thereto in its reports on the Company’s financial statements for such years.

During the fiscal year ended December 31, 2018 and the subsequent interim period through June 19, 2019, there were no “reportable events” (as that term is defined in Item 304(a)(1)(v) of Regulation S-K).

**Item 9A.** ***Controls and Procedures.***

*Evaluation of Disclosure Controls and Procedures*

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2020. The term “disclosure controls and procedures,” as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive and principal financial officers and internal audit function, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2020, our principal executive officer and principal financial officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

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

*Management’s Assessment of Internal Control Over Financial Reporting*

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). The Company’s internal control over financial reporting is a process designed under the supervision of the Company’s Chief Executive Officer and Principal Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2020, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control-Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2020. Management included in its assessment of internal control over financial reporting all consolidated entities.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2020, which is included in the consolidated financial statements in Item 8, Part II of this Annual Report on Form 10-K.

*Changes in Internal Control over Financial Reporting*

There were no changes in our internal control over financial reporting identified in management’s evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the quarter ended December 31, 2020 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Bonanza Creek Energy, Inc.

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of Bonanza Creek Energy, Inc. and subsidiaries (the "Company") as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2020, of the Company and our report dated February 17, 2021, expressed an unqualified opinion on those financial statements.

**Basis for Opinion**

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

**Definition and Limitations of Internal Control over Financial Reporting**

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

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

/s/ Deloitte & Touche LLP

Denver, Colorado
February 17, 2021

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

None.

## PART III

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

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2020.

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

**Item 11. *Executive Compensation*.**

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2020.

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

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2020.

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

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2020.

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

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2020.

## PART IV

**Item 15.** ***Exhibits, Financial Statement Schedules.***

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

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

| Exhibit Number | Description |
|---|---|
| 2.1 | Agreement and Plan of Merger, dated as of November 9, 2020, by and among Bonanza Creek Energy, Inc., Boron Merger Sub, Inc. and HighPoint Resources Corporation (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 9, 2020) |
| 2.2 | Amendment No. 1 to the Agreement and Plan of Merger, by and among Bonanza Creek Energy, Inc., Boron Merger Sub, Inc. and HighPoint Resources Corporation, dated as of January 29, 2021 (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on February 1, 2021) |
| 3.1 | Third Amended and Restated Certificate of Incorporation of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to Bonanza Creek Energy, Inc.'s Registration Statement on Form 8-A filed on April 28, 2017) |
| 3.2 | Fourth Amended and Restated Bylaws of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.2 to Bonanza Creek Energy, Inc.'s Registration Statement on Form 8-A filed on April 28, 2017) |
| 3.3 | Certificate of Designations of Series A Junior Participating Preferred Stock of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 9, 2020) |
| 4.1 | Description of Capital Stock (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Annual Report on Form 10-K filed February 28, 2020) |
| 4.2 | Tax Benefits Preservation Plan, dated as of November 9, 2020, by and between Bonanza Creek Energy, Inc. and Broadridge Corporate Issuer Solutions, Inc., as Rights Agent (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 9, 2020) |
| 10.1 | Warrant Agreement dated as of April 28, 2017, among Bonanza Creek Energy, Inc. and Broadridge Investor Communication Solutions, Inc. as warrant agent (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017) |
| 10.2* | Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017) |
| 10.3* | Form of Non-Qualified Stock Option Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017) |
| 10.4* | Form of Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017) |
| 10.5* | Form of Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018) |
| 10.6* | Form of NYSE Inducement Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 5, 2018) |
| 10.7* | Form of Independent Director Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on November 6, 2019) |
| 10.8* | Form of Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018) |
| 10.9* | Form of Officer Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 6, 2020) |

| | |
|---|---|
| 10.10* | Bonanza Creek Energy, Inc. Sixth Amended and Restated Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.4 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2019) |
| 10.11* | Form of Indemnification Agreement between Bonanza Creek Energy, Inc. and the directors and executive officers of Bonanza Creek Energy, Inc (incorporated by reference to Exhibit 10.7 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017) |
| 10.12* | Letter Agreement dated June 20, 2019 between Bonanza Creek Energy, Inc. and Sandra Garbiso (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 20, 2019) |
| 10.13* | Employment Letter Agreement dated March 30, 2018 between Bonanza Creek Energy, Inc. and Eric T. Greager (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 5, 2018) |
| 10.14* | Employment Letter Agreement dated November 12, 2018 between Bonanza Creek Energy, Inc. and Brant H. DeMuth (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 13, 2018) |
| 10.15* | Form of Officer Employment/Promotion Letter Agreement (incorporated by references to Exhibit 10.22 to Bonanza Creek Energy, Inc.'s Annual Report on Form 10-K filed February 28, 2020) |
| 10.16 | Credit Agreement, dated as of December 7, 2018, among Bonanza Creek Energy, Inc. as borrower, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and an issuing bank (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on December 10, 2018) |
| 10.17 | First Amendment to Credit Agreement dated June 18, 2020, to the Credit Agreement dated as of December 7, 2018, among Bonanza Creek Energy, Inc., as borrower, the guarantors party thereto, JPMorgan Chase Bank N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 22, 2020). |
| 10.18 | Voting and Support Agreement, dated as of November 9, 2020, by and among Bonanza Creek Energy, Inc., Boron Merger Sub, Inc., HighPoint Resources Corporation and Fifth Creek Energy Company, LLC (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 9, 2020) |
| 10.19 | Transaction Support Agreement, dated as of November 9, 2020, by and among HighPoint Resources Corporation, HighPoint Resources Corporation, HighPoint Operating Corporation, Fifth Pocket Production, LLC, HPR Consenting 7% Noteholders, HPR Consenting 8.75% Noteholders, and HPR Consenting Shareholders (as such terms are defined therein) (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 9, 2020) |
| 16.1 | Letter from Grant Thornton LLP to the Securities and Exchange Commission, dated June 25, 2019 (incorporated by reference to Exhibit 16.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 25, 2019) |
| 21.1 | List of subsidiaries (incorporated by references to Exhibit 21.1 to Bonanza Creek Energy, Inc.'s Annual Report on Form 10-K filed February 28, 2020) |
| 23.1† | Consent of Deloitte & Touche LLP |
| 23.2† | Consent of Grant Thornton LLP |
| 23.3† | Consent of Independent Petroleum Engineers, Ryder Scott Company, L.P. |
| 23.4† | Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc. |
| 31.1† | Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) |
| 31.2† | Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) |
| 32.1† | Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith) |
| 32.2† | Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith) |
| 99.1† | Report of Independent Petroleum Engineers, Ryder Scott Company, L.P., for reserves as of December 31, 2020 |
| 101† | The following material from the Bonanza Creek Energy, Inc. Annual Report on Form 10-K for the year ended December 31, 2020 (and related periods), formatted in XBRL (Extensible Business Reporting Language) include (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations and Comprehensive Income, (iii) the Condensed Consolidated Statements of Stockholders' Equity, (iv) the Condensed Consolidated Statements of Cash Flows, and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text |
| 104 | Cover Page Interactive Data File (formatted as Inline XBRL) |

* Management Contract or Compensatory Plan or Arrangement
† Filed or furnished herewith

**SIGNATURES**

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

**BONANZA CREEK ENERGY, INC.**

Date: February 17, 2021

By: /s/ Eric T. Greager

Eric T. Greager,
*President and Chief Executive Officer*
*(principal executive officer)*

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

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

| | | | |
|---|---|---|---|
| Date: | February 17, 2021 | By: | /s/ Eric T. Greager<br>Eric T. Greager,<br>President and Chief Executive Officer<br>*(principal executive officer)* |
| Date: | February 17, 2021 | By: | /s/ Brant DeMuth<br>Brant DeMuth,<br>Executive Vice President and Chief Financial Officer *(principal financial officer)* |
| Date: | February 17, 2021 | By: | /s/ Sandi K. Garbiso<br>Sandi K. Garbiso,<br>*Vice President and Chief Accounting Officer*<br>*(principal accounting officer)* |
| Date: | February 17, 2021 | By: | /s/ Brian Steck<br>Brian Steck,<br>*Chairman of the Board* |
| Date: | February 17, 2021 | By: | /s/ Carrie Hudak<br>Carrie Hudak,<br>*Director* |
| Date: | February 17, 2021 | By: | /s/ Paul Keglevic<br>Paul Keglevic,<br>*Director* |
| Date: | February 17, 2021 | By: | /s/ Jack E. Vaughn<br>Jack E. Vaughn,<br>*Director* |
| Date: | February 17, 2021 | By: | /s/ Scott D. Vogel<br>Scott D. Vogel,<br>*Director* |
| Date: | February 17, 2021 | By: | /s/ Jeffrey E. Wojahn<br>Jeffrey E. Wojahn,<br>*Director* |

**Exhibit 23.1**

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement Nos. 333-229431 and 333-217545 on Form S-8 and 333-251401 and 333-251402 on Form S-4 of our reports dated February 17, 2021, relating to the financial statements of Bonanza Creek Energy, Inc. and its subsidiaries and the effectiveness of Bonanza Creek Energy, Inc. and its subsidiaries' internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2020.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 17, 2021

**Exhibit 23.2**

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We have issued our report dated February 27, 2019 with respect to the consolidated financial statements included in the Annual Report of Bonanza Creek Energy, Inc. on Form 10-K for the year ended December 31, 2020. We consent to the incorporation by reference of said report in the Registration Statements of Bonanza Creek Energy, Inc. on Forms S-8 (File No. 333-229431 and File No. 333-217545) and Forms S-4 (File No. 333-251401 and File No. 333-251402).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 17, 2021

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

633 SEVENTEENTH STREET, SUITE 1700 DENVER, COLORADO 80202 (303) 339-8110

**Exhibit 23.3**

**CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS**

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Bonanza Creek Energy, Inc. for the year ended December 31, 2020. We further consent to the incorporation by reference thereof into Bonanza Creek Energy, Inc.'s Registration Statements on Form S-8 (Registration Nos. 333-217545 and 333-229431).

By: /s/ Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Denver, Colorado
February 17, 2021

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

**Exhibit 23.4**

**CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS**

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Bonanza Creek Energy, Inc. for the year ended December 31, 2020. We further consent to the incorporation by reference thereof into Bonanza Creek Energy, Inc.'s Registration Statements on Form S-8 (Registration Nos. 333-217545 and 333-229431) and on Form S-4 (Registration Nos. 333-251401 and 333-251402).

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 17, 2021

**Exhibit 31.1**

**CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13a- 14(a)**

I, Eric T. Greager, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2020 of Bonanza Creek Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the periods covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 17, 2021

/s/ Eric T. Greager

Eric T. Greager
*President and Chief Executive Officer*
*(principal executive officer)*

**Exhibit 31.2**

**CERTIFICATION OF THE PRINCIPAL FINANCIAL OFFICER PURSUANT TO RULE 13a- 14(a)**

I, Brant DeMuth, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2020 of Bonanza Creek Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the periods covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 17, 2021

/s/ Brant DeMuth

Brant DeMuth
Executive Vice President and Chief Financial Officer *(principal financial officer)*

**Exhibit 32.1**

**Certification of the Chief Executive Officer**
**Pursuant to 18 U.S.C. Section 1350,**
**As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the Annual Report of Bonanza Creek Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Eric T. Greager, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 17, 2021

/s/ Eric T. Greager
Eric T. Greager
President and Chief Executive Officer
*(principal executive officer)*

**Exhibit 32.2**

**Certification of the Principle Financial Officer**
**Pursuant to 18 U.S.C. Section 1350,**
**As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the Annual Report of Bonanza Creek Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brant DeMuth, Executive Vice President and Chief Financial Officer, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 17, 2021

/s/ Brant DeMuth
Brant DeMuth
Executive Vice President and Chief Financial Officer *(principal financial officer)*

# Bonanza Creek Energy, Inc.

**Estimated**

**Future Reserves and Income**

**Attributable to Certain**

**Leasehold and Royalty Interests**

**SEC Parameters**

**As of**

**December 31, 2020**

/s/ Scott James Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 12, 2021

Mr. Jeffrey E. Wojahn
Reserves Committee of Bonanza Creek Energy, Inc.
c/o Bonanza Creek Energy, Inc.
410 17th Street, Suite 1400
Denver, Colorado 80202

Dear Mr. Wojahn:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Bonanza Creek Energy, Inc. (Bonanza Creek) as of December 31, 2020. The subject properties are located in the state of Colorado. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 12, 2021 and presented herein, was prepared for public disclosure by Bonanza Creek in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for all of Bonanza Creek's total net proved oil and gas reserves as of December 31, 2020.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2020, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

**SEC PARAMETERS**
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
**Bonanza Creek Energy, Inc.**
As of December 31, 2020

| | Proved | | | |
|---|---|---|---|---|
| | Developed | | | Total |
| | Producing | Non-Producing | Undeveloped | Proved |
| ***Net Reserves*** | | | | |
| Oil/Condensate – MBarrels | 22,977 | 1,343 | 28,473 | 52,793 |
| Plant Products - MBarrels | 13,736 | 579 | 11,796 | 26,111 |
| Gas – MMCF | 118,217 | 5,003 | 112,508 | 235,728 |
| | | | | |
| ***Income Data ($M)*** | | | | |
| Future Gross Revenue | $998,598 | $56,177 | $1,161,680 | $2,216,455 |
| Deductions | 401,525 | 36,328 | 755,315 | 1,193,168 |
| Future Net Income (FNI) | $597,073 | $19,849 | $ 406,365 | $1,023,287 |
| | | | | |
| Discounted FNI @ 10% | $340,040 | $10,806 | $ 86,208 | $ 437,054 |

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Bonanza Creek. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, and development costs, certain abandonment costs net of salvage, and routine artificial lift expenditures. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 90 percent and gas reserves account for the remaining 10 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

| Discount Rate Percent | Discounted Future Net Income ($M) As of December 31, 2020 Total Proved |
|---|---|
| 8.0 | $502,231 |
| 9.0 | $467,844 |
| 12.0 | $384,328 |
| 12.5 | $372,706 |

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

***Reserves Included in This Report***

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein include volumes of gas consumed in operations as reserves.

Reserves are "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." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Bonanza Creek's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "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." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, r reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Bonanza Creek's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, wellhead siting restrictions, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Bonanza Creek owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

***Estimates of Reserves***

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods, which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are 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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through November 2020 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Bonanza Creek or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved developed non-producing and undeveloped reserves included herein were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Bonanza Creek or which we have obtained from public data sources that were available through November 2020. The data utilized from the analogues were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Bonanza Creek has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Bonanza Creek with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, production taxes, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Bonanza Creek. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

***Future Production Rates***

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Bonanza Creek. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling and/or completing wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

***Hydrocarbon Prices***

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Bonanza Creek furnished us with the above mentioned average prices in effect on December 31, 2020. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Bonanza Creek. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Bonanza Creek to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

| Geographic Area | Product | Price Reference | Average Benchmark Prices | Average Realized Prices |
|---|---|---|---|---|
| North America | | | | |
| United States | Oil | WTI Cushing | $39.57/BBL | $34.96/BBL |
| | Plant Products | WTI Cushing | $39.57/BBL | $6.12 /BBL |
| | Gas | Henry Hub | $1.985/MMBTU | $0.95/MCF |

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

***Costs***

Operating costs for the leases and wells in this report were furnished by Bonanza Creek and are based on the operating expense reports of Bonanza Creek and include only those costs directly applicable to the leases or wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Bonanza Creek**.** No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Bonanza Creek and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Bonanza Creek were accepted without independent verification. These costs are reflected in cash flow tables in the “Other Deductions” column. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Bonanza Creek’s estimate. When material, routine artificial lift installation costs are included in the “Other Deductions” column.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Bonanza Creek’s plans to develop these reserves as of December 31, 2020. The implementation of Bonanza Creek’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Bonanza Creek's management. As the result of our inquiries during the course of preparing this report, Bonanza Creek has informed us that the development activities included herein have been subjected to and received the internal approvals required by Bonanza Creek's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Bonanza Creek. Bonanza Creek has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Bonanza Creek has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2020, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Bonanza Creek were held constant throughout the life of the properties.

***Standards of Independence and Professional Qualification***

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Bonanza Creek. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

***Terms of Usage***

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Bonanza Creek.

Bonanza Creek makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Bonanza Creek has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Bonanza Creek, of the references to our name, as well as to the references to our third party report for Bonanza Creek, which appears in the December 31, 2020 annual report on Form 10-K of Bonanza Creek. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Bonanza Creek.

We have provided Bonanza Creek with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Bonanza Creek and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

/s/ Scott James Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President

SJW (LPC)/pl

## Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at https://www.ryderscott.com/company/employees/denver-employees.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co-Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

**PETROLEUM RESERVES DEFINITIONS**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

***PREAMBLE***

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

*Reserves are 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.* All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

## RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

***Reserves.*** *Reserves are 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.*

*Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

## PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

*(ii) In the absence of data on fluid 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 portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.*

*(iv) Reserves which 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.*

**PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

**and**

**2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)**
**Sponsored and Approved by:**
**SOCIETY OF PETROLEUM ENGINEERS (SPE)**
**WORLD PETROLEUM COUNCIL (WPC)**
**AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)**
**SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)**
**SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)**
**SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)**
**EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)**

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

**DEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

*Developed oil and gas reserves are reserves of any category that can be expected to be recovered:*

> *(i) 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; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

**Developed Producing (SPE-PRMS Definitions)**

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

***Developed Producing Reserves***

*Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.*

*Improved recovery reserves are considered producing only after the improved recovery project is in operation.*

***<u>Developed Non-Producing</u>***
*Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.*

***<u>Shut-In</u>***
*Shut-in Reserves are expected to be recovered from:*
*(1) completion intervals that are open at the time of the estimate but which have not yet started producing;*
*(2) wells which were shut-in for market conditions or pipeline connections; or*
*(3) wells not capable of production for mechanical reasons.*

***<u>Behind-Pipe</u>***
*Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.*

*In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

## <u>UNDEVELOPED RESERVES (SEC DEFINITIONS)</u>

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

*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.*

*(i) 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.*

*(ii) 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 the specific circumstances, justify a longer time.*

*(iii) Under no circumstances shall estimates for 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.*