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, 2018

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

(720) 440-6100

(Registrant's telephone number, including area code)

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

(Title of Class)	(Name of Exchange)
Common Stock, par value $0.01 per share	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 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, 2018, based upon the closing price of $37.87 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $776,136,334. Excludes approximately 13,858 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 25, 2019: 20,558,591

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, 2018, as incorporated by reference into Part III of this report for the year ended December 31, 2018.

BONANZA CREEK ENERGY, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2018

TABLE OF CONTENTS

Information Regarding Forward-Looking Statements

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

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

- 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 effectiveness of vapor control systems at central tank batteries;
- 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 revenues and losses;
- the timing and success of specific projects;
- our implementation of standard and long reach laterals in the Wattenberg Field;
- our use of multi-well pads to develop the Niobrara and Codell formations;
- intention to continue to optimize enhanced completion techniques and well design changes;
- 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 PUDs 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; and
- other statements concerning our operations, economic performance and financial condition.

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

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

- the risk factors discussed in Part I, Item 1A of this Annual Report on Form 10-K;
- further declines or volatility in the prices we receive for our oil, natural gas liquids and natural gas;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- ability of our customers to meet their obligations to us;
- our access to capital;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves;
- 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;
- 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 curing 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 priced received.

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

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

"Economically producible." The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the 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.

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

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

"Exploratory well." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

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

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

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

“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.

“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 and using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices (after adjustment for differentials in location and quality) for each of the preceding twelve months. Please refer to 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 a Denver-based exploration and production company focused on the extraction of oil and associated liquids-rich natural gas in the Rocky Mountain region of the United States. Bonanza Creek Energy, Inc. was incorporated in Delaware on December 2, 2010 and went public in December 2011.

The Company's assets and operations are concentrated in the rural portions of unincorporated Weld County within the Wattenberg Field. We operate approximately 80% 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.

The challenging commodity price environment that began in late 2014 and continued through 2017 improved steadily during the majority of 2018. While commodity prices improved, they continued to be volatile. Nevertheless, we believe we remain well-positioned in this environment due to our healthy balance sheet, ample liquidity, improved inventory of economic drilling locations, and our operational flexibility which allows us to respond to commodity price fluctuations.

During 2018, 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 a significant growth in reserves. Additionally, we maintained our conservative balance sheet and significantly improved our available liquidity by entering into a larger, more flexible, reserve-based credit facility. We intend to continue our operational focus in 2019, emphasizing full-cycle returns and capital discipline. We will continue to monitor the ongoing commodity price environment and expect to retain the operational flexibility to adjust our drilling and completion plans in response to market 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 production growth with maintaining a conservative balance sheet. Key aspects of our strategy include:

- *Multi-well pad development across our leasehold.* We believe horizontal development is the most efficient 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. 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 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. Hedge a portion of its production to reduce realized price volatility allowing for enhanced certainty of development program rates of return and improved capital allocation decisions.

Significant Developments in 2018

Leadership

During 2018, the Company secured key leadership roles in order to help develop and achieve the Company's strategies.

Effective April 11, 2018, the Company appointed Eric T. Greager as the new President and Chief Executive Officer of the Company. Mr. Greager has over 20 years of experience in the oil and gas industry, including exposure to both the operating and technical aspects of the industry. Mr. Greager previously served as a Vice President and General Manager at Encana Oil & Gas (USA) Inc.

Effective November 13, 2018, the Company appointed Brant H. DeMuth as the new Executive Vice President and Chief Financial Officer and principal financial officer of the Company. Mr. DeMuth has 34 years of management and finance experience in capital markets and the oil and gas industry. Mr. DeMuth previously served as Vice President of Finance and Treasurer at SRC Energy Inc.

Operations

In order to focus on and partially fund the development of our core assets, we divested of our Mid-Continent region and North Park Basin assets. We successfully sold our Mid-Continent assets on August 6, 2018 for net proceeds of $102.9 million which resulted in a gain of $27.3 million. The Company sold its North Park Basin assets on March 9, 2018 for minimal net proceeds and full release of all current and future obligations.

We continued to take steps to improve our access to gas processing in the DJ Basin, which resulted in improved costs, greater reliability, and greater optionality than available to many other operators in the basin while enhancing the value of our Rocky Mountain Infrastructure, LLC (“RMI”) system. RMI provides low gathering system pressures at the wellhead and access to four gas processors through eleven interconnects. This flexibility helps ensure product flow from both existing and new wells. We will continue to look for ways to improve our access to gas gathering and processing services.

Our cost reductions in 2018 were focused primarily around compression contracts, water services, labor, and well servicing. Through these cost saving efforts the Company experienced a 46% reduction in Wattenberg Field lease operating expense per Boe when comparing the fourth quarters of 2018 and 2017. Further efficiency improvements will continue to be a focus for the Company, with our per-unit costs continuing to benefit from production growth in 2019 and beyond. The Company incurred some non-recurring costs in the first half of the year, including one-time facility emissions modeling and compressor replacement costs.

The Company accelerated 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 drilling programs. Fluid volumes and types, proppant volumes and types, stage spacing, well spacing, and flowback techniques were the primary variables that were tested throughout the 2018 program. The Company will 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 first half of 2018 with a second rig added mid-year to coincide with our access to additional gas processing capacity. We discontinued our use of the second rig in late 2018 in response to the weakening commodity price environment. Wattenberg sales volumes increased by approximately 48% when comparing the fourth quarters of 2018 and 2017.

Consistent with the Company's 2018 budget, our capital program equaled approximately $275.3 million, which resulted in the drilling of 77 gross operated wells, turning to sales 41 gross operated wells and participating in the drilling and completion of one non-operated well.

The following table summarizes our estimated proved reserves as of December 31, 2018:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed				
Rocky Mountain	23,725	79,630	11,703	48,699
Undeveloped				
Rocky Mountain	40,629	85,382	13,227	68,086
Total Proved	64,354	165,012	24,930	116,785

Total Wattenberg Field proved reserves as of December 31, 2018 increased by approximately 29% over the comparable period in 2017.

The following table summarizes our PV-10 reserve value, sales volumes, and projected capital spend as of December 31, 2018:

	Estimated Proved Reserves at December 31, 2018[1]				Sales Volumes for the Year Ended December 31, 2018			
	Total Proved (MBoe)	% of Total	% Proved Developed	PV-10 ($ in MM)[2]	Average Net Daily Sales Volumes (Boe/d)	% of Total	Projected 2019 Capital Expenditures ($ in millions)	Gross Proved Undeveloped Drilling Locations as of December 31, 2018[4]
Rocky Mountain	116,785	100%	42%	$ 955.0	15,844	90%	$ 230-255	300
Mid-Continent[3]	—	—%	—%	—	1,728	10%	—	—
Total	116,785	100%	42%	$ 955.0	17,572	100%	$ 230-255	300

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(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 $65.56 per Bbl WTI and $3.10 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $6.27 per Bbl for crude oil and a decrease of $0.82 per MMBtu for natural gas.

(2) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil, natural gas, and natural gas liquid reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices, after adjustment for differentials in location and quality, for each of the preceding twelve months. We believe that PV-10 provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. We believe that PV-10 is relevant and useful for evaluating the relative monetary significance of our reserves. Professional analysts and sophisticated investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable in evaluating the Company and our reserves. PV-10 is not intended to represent the current market value of our estimated reserves. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. Please refer to the *Reconciliation of PV-10 to Standardized Measure* presented in the "Reserves" subsection of Item 1 below.

(3) Mid-Continent sales volumes were 1,728 Boe/d for 2018, which is comprised of 1,550 Boe/d of production net to our interest and 178 Boe/d sales volumes from our percentage-of-proceeds contracts. We sold all of our assets within the Mid-Continent region on August 6, 2018.

(4) The Company has 444.5 standard reach lateral equivalent gross proved undeveloped drilling locations as of December 31, 2018.

Our Operations

As of December 31, 2018, our operations are solely focused in the rural portions of the Wattenberg Field in the Rocky Mountain region. The Company sold all of its assets within the Mid-Continent region and North Park Basin on August 6, 2018 and March 9, 2018, respectively.

Rocky Mountain Region

Our Rocky Mountain Region consists of one operating area in the Wattenberg Field in Weld County, Colorado. As of December 31, 2018, our estimated proved reserves in the Rocky Mountain region were 116,785 MBoe, which represented 100% of our total estimated proved reserves and contributed 15,844 Boe/d, or 90%, of sales volumes during 2018.

Wattenberg Field - Weld County, Colorado. Our operations are located in the rural portions of the oil and liquids-weighted extension area of the Wattenberg Field targeting the Niobrara and Codell formations. As of December 31, 2018, our Wattenberg position consisted of approximately 92,000 gross (65,000 net) acres.

The Wattenberg Field is now primarily developed for the Niobrara and Codell formations using horizontal drilling and multi-stage fracture stimulation techniques. We believe the Niobrara B and C benches have been fully delineated on our legacy acreage, while the Codell formation has been delineated on our western legacy acreage. Our northern and southern acreage positions are currently being delineated.

As of December 31, 2018, we had a total of 695 gross producing wells, of which 507 were horizontal wells. Our sales volumes for the fourth quarter of 2018 were 17,748 Boe/d. As of December 31, 2018, our working interest for all producing wells averaged approximately 80% and our net revenue interest was approximately 66%.

We drilled and participated in drilling 116.5 gross (92.2 net) standard reach lateral (“SRL”) equivalent wells in 2018 in the Wattenberg Field. As of December 31, 2018, we have an identified drilling inventory of approximately 300 gross (200.3 net) proved undeveloped (“PUD”) drilling locations (444.5 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, 2018.

	SRL		MRL		XRL	
	Drilled	**Completed**	**Drilled**	**Completed**	**Drilled**	**Completed**
Niobrara - Operated	34	16	7	2	33	20
Codell - Operated	2	3	—	—	1	—
Niobrara - Non-operated	—	—	—	—	1	1

The Company’s Rocky Mountain Infrastructure (“RMI”) gathering asset has eleven interconnects to four independent gas processors. This system improves flow assurance and operates at relatively low line pressure at the wellhead. Reduced gathering system pressure at the wellhead enhances well performance and the system’s interconnects provide for delivery flexibility, enabling the Company to maximize available price realizations.

The Company’s 2019 capital budget contemplates the continuous use of one drilling rig. The rig is scheduled to drill large-scale five to eighteen well pads throughout our legacy west, central and east acreage position. The Company plans to complete wells in 2019 using slickwater designs similar to the techniques used in 2018 that resulted in significant well improvements. The Company will continue to remain agile and modify drilling and completion techniques as additional data from both operated and non-operated wells becomes available.

Assuming a one rig drilling program, the Company anticipates 2019 Wattenberg production growth to be greater than 30% year-over-year as compared to Wattenberg-only production realized in 2018. Furthermore, the Company anticipates being able to grow Wattenberg production by approximately 20% in 2020 as compared to 2019 using a one-and-a-half operated rig program.

Our drilling and completion capital investment in 2019 is expected to be approximately $210.0 million to $220.0 million, which will support drilling 59 gross wells and turning to sales 45 gross wells. This drilling and completion capital budget includes an estimated $15.0 million for non-operated activity. An additional $20.0 million to $35.0 million in capital is contemplated for investments in infrastructure, land, and seismic. The 2019 drilling and completion program by well type is presented in the following table.

	SRL		MRL		XRL	
	Drilled	Completed	Drilled	Completed	Drilled	Completed
Niobrara	33	24	—	5	26	16

North Park Basin - Jackson County, Colorado. We successfully sold all of our North Park assets on March 9, 2018 for minimal net proceeds and full release of all current and future obligations. Our sales volumes for 2018, prior to the divestiture, were10 Boe/d.

Mid-Continent Region

We successfully sold our Mid-Continent assets on August 6, 2018 for $117.0 million, prior to customary closing adjustments, which resulted in net proceeds of $102.9 million. We achieved a sales volume rate for 2018 of 1,728 Boe/d prior to the divestiture, or 10% of sales volume for 2018. At December 31, 2017, the Company had 300 gross producing vertical wells and proved reserves of approximately 10,419 MBoe.

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, 2018, 2017 and 2016 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. The PV-10 values shown in the following table are not intended to represent the current market value of our estimated proved reserves. Neither prices nor costs have been escalated. The actual quantities and present values of our estimated proved reserves may vary from what we have estimated.

The table below summarizes our estimated proved reserves as of December 31, 2018, 2017 and 2016 for each of the regions and currently producing fields in which we operate. The proved reserve estimates as of December 31, 2018 and 2017 were prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), our third-party independent reserve engineers. The proved reserves as of December 31, 2016 are based on reports prepared by our internal corporate reservoir engineering group, of which 100% were audited by NSAI. For more information regarding our independent reserve engineers, please see *Independent Reserve Engineers* below. The information in the following table is not intended to represent the current market value of our proved reserves nor does it give any effect to or reflect our commodity derivatives or current commodity prices.

Region/Field	At December 31, 2018	2017	2016
	(MMBoe)		
Rocky Mountain	**116.8**	**90.5**	**78.0**
Wattenberg	116.8	90.3	77.8
North Park	—	0.2	0.2
Mid-Continent	**—**	**11.5**	**12.7**
Dorcheat Macedonia	—	10.4	11.6
McKamie Patton	—	1.1	1.1
Total	**116.8**	**102.0**	**90.7**

The following table sets forth more information regarding our estimated proved reserves at December 31, 2018, 2017 and 2016:

	At December 31, 2018	2017	2016
Reserve Data[1]:			
Estimated proved reserves:			
Oil (MMBbls)	64.4	52.9	50.1
Natural gas (Bcf)	165.0	157.7	138.0
Natural gas liquids (MMBbls)	24.9	22.8	17.5
Total estimated proved reserves (MMBoe)[2]	116.8	102.0	90.7
Percent oil and liquids	76%	74%	75%
Estimated proved developed reserves:			
Oil (MMBbls)	23.7	25.8	26.3
Natural gas (Bcf)	79.6	92.7	86.0
Natural gas liquids (MMBbls)	11.7	12.7	10.0
Total estimated proved developed reserves (MMBoe)[2]	48.7	53.9	50.6
Percent oil and liquids	73%	71%	72%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	40.6	27.1	23.8
Natural gas (Bcf)	85.4	65.0	52.0
Natural gas liquids (MMBbls)	13.2	10.1	7.5
Total estimated proved undeveloped reserves (MMBoe)[2]	68.1	48.1	40.1
Percent oil and liquids	79%	77%	78%

(1) Proved reserves were calculated using the preceding twelve month unweighted arithmetic average of the first-day-of-the-month prices, which were $65.56 per Bbl WTI and $3.10 per MMBtu HH, $51.34 per Bbl WTI and $2.98 per MMBtu HH, and $42.75 per Bbl WTI and $2.48 per MMBtu HH for the years ended December 31, 2018, 2017 and 2016, 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, 2018 reserve report are included in our development plan and are scheduled to be drilled within five years from the date they were initially recorded. The Company's management evaluated the proved undeveloped drilling plan using 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 one-rig program for 2019, a one-and-a-half rig program in 2020, and two rigs starting in the second half of 2022, which allows all PUDs to be drilled within the allotted five-year window. We typically book 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, we utilized reliable geologic and engineering technology. The reliable technologies used to establish our proved reserves are a combination of pressure performance, geologic mapping, offset productivity, electric logs, seismic, and production data.

As of December 31, 2018, the total proved undeveloped gross location count in our Wattenberg Field was 300.0 (444.5 SRL equivalents), compared to 205.0 (248.0 SRL equivalents) gross location counts as of December 31, 2017. Our five-year drilling program captures these proved undeveloped locations. For the year ending December 31, 2018, approximately 60% of the proved undeveloped locations are spaced on 80 acres within a single bench and approximately 40% are planned to be drilled on 80/40 geometry, which involves drilling wells on 80 acre spacing on each of two benches with a 40 acre offset between wells on the upper and lower bench.

The Company-wide and Wattenberg Field estimated proved reserves at December 31, 2018 were 116.8 MMBoe, a 14% and 29% increase from the Company-wide and Wattenberg Field estimated proved reserves at December 31, 2017, respectively. The net increase in our Company-wide reserves of 14.8 MMBoe is the result of a 28.8 MMBoe increase from PUD and capital additions, coupled with a 3.8 MMBoe increase in cost and engineering revisions, and a 2.3 MMBoe increase due to pricing, offset by divested reserves of 11.2 MMBoe, 2.5 MMBoe of undeveloped reserves removed from our five-year drilling program, and 2018 production of 6.4 MMBoe.

Positive adjustments to the estimated proved reserves during 2018 consisted of pricing and LOE changes, reserve additions from capital and PUD developments, and engineering revisions. The positive pricing revision of 2,333 Mboe resulted from an increase in average commodity price from $51.34 per Bbl WTI and $2.98 per MMBtu HH for the year ended December 31, 2017 to $65.56 per Bbl WTI and $3.10 per MMBtu HH for the year ended December 31, 2018. The 1,536 MBoe LOE revision is due to continued decreases in LOE as a result of numerous cost-cutting initiatives completed over the past few years. The 28,832 Mboe in PUD and capital additions is the result of turning to sales 41 operated horizontal locations in the Niobrara and Codell formations in the Wattenberg Field during 2018 and adding infill and extension PUD locations that are on the 2019 rig schedule.

Estimated proved reserves at December 31, 2017 were 102.0 MMBoe, a 13% increase from estimated proved reserves of 90.7 MMBoe at December 31, 2016. Approximately 89% of our December 31, 2017 proved reserves were attributed to the Rocky Mountain region, and 99.8% of the Rocky Mountain proved reserves were attributed to the Wattenberg Field. The net increase in our reserves of 11.3 MMBoe was the result of a 15.5 MMBoe increase from PUD and capital additions, coupled with a 7.1 MMBoe increase in net positive cost revisions (reserve prices less drilling and completion costs and LOE), and a 2.1 MMBoe increase due to positive engineering revisions, offset by PUD demotions of 7.6 MMBoe and 2017 production of 5.7 MMBoe.

Positive adjustments to the estimated proved reserves during 2017 consisted of pricing and LOE changes, reserve additions from capital and PUD developments, and engineering revisions. The positive pricing revision of 5,405 Mboe resulted from an increase in average commodity price from $42.75 per Bbl WTI and $2.48 per MMBtu HH for the year ended December 31, 2016 to $51.34 per Bbl WTI and $2.98 per MMBtu HH for the year ended December 31, 2017. The 1,672 MBoe LOE revision was due to continued decreased LOE as a result of numerous cost-cutting initiatives completed over the past few years. The 15,547 Mboe in PUD and capital additions was the result of turning to sales 10 operated and 24 non-operated unproved horizontal locations in the Niobrara and Codell formations in the Wattenberg Field during 2017 and adding infill PUD locations that were the 2018 rig schedule, offset by PUD locations that were removed due to a shift within our development strategy.

Estimated proved reserves at December 31, 2016 were 90.7 MMBoe, a 10% decrease from estimated proved reserves of 101.3 MMBoe at December 31, 2015. The net decrease in our reserves of 10.6 MMBoe was the result of 2016 production of 7.8 MMBoe coupled with writing off 16.4 MMBoe of PUDs and 1.9 MMBoe of other engineering revisions, offset by additions in extensions, discoveries, and infills of 10.8 MMBoe and net positive cost revisions (reserve prices less drilling and completion costs and LOE) of 4.7 MMBoe.

The 10.8 MMBoe addition in extensions, discoveries, and infills in 2016 was primarily the result of turning to sales five operated and six non-operated unproved horizontal locations in the Niobrara formation that were in progress at year-end 2015, and drilling and completing three non-operated unproved horizontal wells and one operated unproved vertical well in the

Niobrara formation in the Wattenberg Field during 2016. In 2016 our five-year drilling plan was adjusted to focus on locations that were adjacent to existing production facilities. As a result, 42 PUD locations were added and 38 PUD locations under the prior plan were removed.

Total Company positive engineering revisions as of December 31, 2016, were 28,625 Mboe, of which 32,899 Mboe were related to positive reserve changes in the Wattenberg Field and 4,416 Mboe were related to negative reserve changes in the Dorcheat Macedonia Field. The overall positive engineering revision is offset by a negative pricing revision of 39,222 Mboe in the Wattenberg Field and 2,778 Mboe in the Dorcheat Macedonia Field. The negative pricing revision of 42,143 Mboe for the Company resulted from a decrease in average commodity price from $50.28 per Bbl WTI and $2.59 per MMBtu HH for the year ended December 31, 2015 to $42.75 per Bbl WTI and $2.48 per MMBtu HH for the year ended December 31, 2016. The majority of the positive revisions in the Wattenberg Field resulted from a combination of decreased drilling and completion costs and a continued decrease in LOE, which had begun in 2015. Our total proved undeveloped location count in the Wattenberg Field as of December 31, 2016 was 210 (226 standard reach lateral equivalents) and 204 as of December 31, 2015.

Reconciliation of PV-10 to Standardized Measure

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

The following table provides a reconciliation of PV-10 to Standardized Measure at December 31, 2018, 2017 and 2016:

	December 31,		
	2018	2017	2016
	(in millions)		
PV-10	$ 955.0	$ 598.5	$ 276.9
Present value of future income taxes discounted at 10%(1)	—	—	—
Standardized Measure	$ 955.0	$ 598.5	$ 276.9

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(1) The tax basis of our oil and gas properties as of December 31, 2018, 2017, and 2016 provides more tax deduction than income generated from our oil and gas properties when the reserve estimates were prepared using $65.56 per Bbl WTI and $3.10 per MMBTU HH, $51.34 per Bbl WTI and $2.98 per MMBtu HH, and $42.75 per Bbl WTI and $2.48 per MMBtu HH, respectively.

Proved Undeveloped Reserves

	Net Reserves, MBoe At December 31,		
	2018	2017	2016
Beginning of year	48,082	40,057	49,184
Converted to proved developed	(8,643)	(2,196)	(1,352)
Additions from capital program	27,978	11,717	—
Removed from capital program	(2,527)	(7,577)	
Acquisitions	—	—	—
Revisions	3,196	6,081	(7,775)
End of year	68,086	48,082	40,057

At December 31, 2018, our proved undeveloped reserves were 68,086 MBoe, all of which are scheduled to be drilled within five years from the date they were initially recorded. During 2018, the Company converted 18% of its proved undeveloped reserves (29 gross wells representing net reserves of 8,643 MBoe) at a cost of $127.8 million. The net increase of 27,978 Mboe in PUD additions is the result of adding 92 XRL and 18 SRL infill PUD locations in the Company's southern “French Lake” area and 14 XRL and 12 SRL PUD locations in other areas that are captured in our five-year drilling program. Twelve PUD locations were removed from our reserve base as they were no longer part of our five-year drilling program.

At December 31, 2017, our proved undeveloped reserves were 48,082 MBoe, all of which were scheduled to be drilled within five years of their initial proved booking date. During 2017, the Company converted 6% of its proved undeveloped reserves (seven gross wells representing net reserves of 2,196 MBoe) at a cost of $26.1 million. The net increase of 4,140 Mboe in PUD additions are the result of adding infill PUD locations that were on the 2018 rig schedule, offset by PUD locations that were removed due to a changes in our development strategy. The increase in revisions was primarily due to the forecasted production uplift resulting from enhanced completion designs.

At December 31, 2016, our proved undeveloped reserves were 40,057 MBoe, all of which were scheduled to be drilled within five years of their initial proved booking date. During 2016, the Company converted 3% of its proved undeveloped reserves (seven gross wells representing net reserves of 1,352 MBoe) at a cost of $16.2 million. Our 2016 capital program was suspended after the first quarter, and no proved undeveloped locations were added as a result of drilling. The net decrease in our PUD reserves from December 31, 2015 to December 31, 2016 was mainly the result of removing 7.8 MMBoe of PUDs in the Mid-Continent region, as drilling focus shifted entirely to the Wattenberg Field. Thirty-eight Wattenberg proved undeveloped locations not within areas in close proximity to existing CPFs were demoted and were replaced with 42 infill proved undeveloped locations that were near existing CPFs.

Internal controls over reserves estimation process

Our policies regarding internal controls over the recording of reserves estimates require reserves to be in compliance with SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The Company’s Reserves Committee reviews significant reserve changes on an annual basis and our third-party independent reserve engineers, NSAI, is engaged by and has direct access to the Reserves Committee. The reserves estimates for the year ended December 31, 2018 and 2017 shown herein have been independently prepared by NSAI. These NSAI reserve estimates are reviewed by our in-house petroleum engineer who oversees and controls preparation of the reserve report data by working with NSAI to ensure the integrity, accuracy and timeliness of data furnished to NSAI for their evaluation process. The Company's technical person who was primarily responsible for overseeing the preparation of our reserve estimates was our Manager of Corporate Reserves who has over 30 years of experience in the oil and gas industry, including four years in her role at the Company. Her professional qualifications include a bachelor's degree in Petroleum Engineering from the University of Wyoming and a master's degree in Petroleum Engineering from the Colorado School of Mines.

For the year ended December 31, 2016 the Company prepared the reserves estimate, which were audited by NSAI. The responsibility for compliance in reserves estimation was delegated to our internal corporate reservoir engineering group. The Company's Corporate Reserves Manager, at that time, had a Bachelor of Science degree in Geological Engineering and a Master of Science degree in Mineral Economics from the Colorado School of Mines and had been in the petroleum industry for 41 years. Our internal corporate reservoir engineering group had over 85 years of industry experience.

Independent Reserve Engineers

The reserves estimates shown herein for December 31, 2018 and 2017 have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. 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 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 2018 and the beginning of 2019. 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 the global economy. 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 0.3% and our PV-10 value as of December 31, 2018 would decrease by approximately 23% or $223.1 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 0.4% and our PV-10 value as of December 31, 2018 would increase by approximately 24% or $229.8 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 Operation*s.

	Successor		Predecessor	
	For the Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	For the Year Ended December 31, 2016
Oil:				
Total Production (MBbls)	3,840.8	2,012.7	1,068.5	4,309.9
Wattenberg Field	3,500.2	1,568.5	834.4	3,470.7
Dorcheat Macedonia Field	340.6	379.9	193.2	750.0
Average sales price (per Bbl), including derivatives(3)	$ 54.77	$ 46.44	$ 48.29	$ 39.57
Average sales price (per Bbl), excluding derivatives(3)	$ 59.38	$ 47.18	$ 48.29	$ 35.32
Natural Gas:				
Total Production (MMcf)	8,591.2	5,767.5	3,242.5	11,906.3
Wattenberg Field	7,408.3	4,588.1	2,564.9	9,574.8
Dorcheat Macedonia Field	1,182.8	1,179.3	677.6	2,331.4
Average sales price (per Mcf), including derivatives(4)	$ 2.39	$ 2.29	$ 2.57	$ 1.76
Average sales price (per Mcf), excluding derivatives(4)	$ 2.45	$ 2.29	$ 2.57	$ 1.76
Natural Gas Liquids:				
Total Production (MBbls)	1,141.2	712.9	422.7	1,491.1
Wattenberg Field	1,048.3	656.2	391.1	1,354.3
Dorcheat Macedonia Field	92.8	56.8	31.6	136.8
Average sales price (per Bbl), including derivatives	$ 22.46	$ 18.38	$ 17.52	$ 12.39
Average sales price (per Bbl), excluding derivatives	$ 22.46	$ 18.38	$ 17.52	$ 12.39
Oil Equivalents:				
Total Production (MBoe)	6,413.8	3,686.9	2,031.6	7,785.4
Wattenberg Field	5,783.2	2,989.4	1,653.0	6,420.8
Dorcheat Macedonia Field	630.6	633.2	337.7	1,275.4
Average Daily Production (Boe/d)	17,572.0	15,048.4	16,930.4	21,271.7
Wattenberg Field	15,844.0	12,201.5	13,774.9	17,543.4
Dorcheat Macedonia Field	1,728.0	2,584.5	2,814.3	3,484.5
Average Production Costs (per Boe)(1)(2)	$ 7.11	$ 9.28	$ 8.20	$ 7.25

(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 of 6,413.8 MBoe, 3,686.9 MBoe, 2,031.6 MBoe, and 7,785.4 MBoe for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and the 2016 Predecessor Period, respectively. Total production volumes exclude volumes from our percentage-of-proceeds contracts in our Mid-Continent region of 65.0 MBoe, 77.9 MBoe, 41.9 MBoe, and 150.1 MBoe for the Current Successor Period 2017 Successor Period, 2017 Predecessor Period, and the 2016 Predecessor Period, respectively.

(3) Crude oil sales excludes $0.6 million, $0.2 million, $0.1 million, and $0.5 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and the 2016 Predecessor Period, respectively.

(4) Natural gas sales excludes $1.3 million, $0.8 million, $0.4 million, and $1.5 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and the 2016 Predecessor Period, respectively.

Principal Customers

One of our customers, NGL Crude Logistics, LLC comprised 66% of our total revenue for the year ended December 31, 2018. No other single non-affiliated customer accounted for 10% or more of our oil and natural gas sales in 2018. 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 entered into a new purchase agreement upon emergence from bankruptcy. The terms of the agreement consists of defined volume commitments over an initial seven-year term. The Company will be required to make periodic deficiency payments for any shortfalls in delivering minimum volume commitments, which are set in six-month periods beginning in January 2018. The Company's capital program is designed to exceed these minimum volume commitments. During 2018, the average minimum volume commitment was approximately 10,100 barrels per day and increased by approximately 41% from 2018 to 2019 and approximately 3% each year thereafter for the remainder of the contract, to a maximum of approximately 16,000 barrels per day. The aggregate financial commitment fee over the seven-year term, based on the minimum volume commitment schedule (as defined in the agreement) and the applicable differential fee, is $136.3 million as of December 31, 2018. Please refer to *Part II, Item 8, Note 8 - Commitments and Contingencies* for additional discussion.

Productive Wells

The following table sets forth the number of producing oil and natural gas wells in which we owned a working interest at December 31, 2018.

	Oil(2)		Natural Gas(1)		Total(2)		Operated(2)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	695.0	556.1	—	—	695.0	556.1	580.0	464.1

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

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2018, 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		
	Gross	Net	Gross	Net	Gross	Net	PV-10
Wattenberg Field - Rocky Mountain	66,479	54,681	25,685	10,739	92,164	65,420	955.0
Total	66,479	54,681	25,685	10,739	92,164	65,420	$ 955.0

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 by area as of December 31, 2018 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 2019		Expiring 2020		Expiring 2021	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	1,019	432	7,962	2,959	2,723	1,429

Drilling Activity

The following table describes the exploratory and development wells we drilled and completed during the years ended December 31, 2018, 2017, and 2016.

	For the Years Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive Wells	—	—	—	—	—	—
Dry Wells	—	—	—	—	—	—
Total Exploratory	—	—	—	—	—	—
Development						
Productive Wells	27	21.9	4	4.0	4	3.9
Dry Wells	—	—	—	—	—	—
Total Development	27	21.9	4	4.0	4	3.9
Total	27	21.9	4	4.0	4	3.9

The following table describes the present operated drilling activities as of December 31, 2018.

	As of December 31, 2018	
	Gross	Net
Exploratory		
Rocky Mountain	—	—
Total Exploratory	—	—
Development		
Rocky Mountain	50	40.4
Total Development	50	40.4
Total	50	40.4

Capital Expenditure Budget

The Company's 2019 capital budget of $230.0 million to $255.0 million assumes a continuous one-rig development pace. The drilling and completion portion of the budget is expected to be approximately $210.0 million to $220.0 million, which will support drilling 59 gross wells and turning to sales 45 gross wells. Included in the drilling completion budget is $15.0 million for non-operated capital. Of the operated wells planned to be drilled, approximately 26 are XRL wells and 33 are SRL wells. Of the wells planned to be completed, 16 are XRL wells, five are MRL wells, and 24 are SRL wells. The remaining 2019 capital budget of $20.0 million to $35.0 million is to support infrastructure and leasehold costs. Actual capital expenditures could vary significantly based on, among other things, market conditions, commodity prices, drilling and completion costs, well results, and changes in the borrowing base under our Current Credit Facility.

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. We have successfully hedged approximately 54% and 59% of our average 2019 guided production as of December 31, 2018 and as of the filing date of this report, respectively.

As of December 31, 2018, 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
1Q19								
Cashless Collar	4,000	$50.88/$63.83	7,600	$2.75/$3.22	—	—	—	—
Swap	4,000	$59.16	1,500	$3.13	7,600	$0.67	10,000	$2.17
Put	500	$55.00	—	—	—	—	—	—
2Q19								
Cashless Collar	5,330	$54.42/$67.57	2,505	$2.75/$3.22	—	—	—	—
Swap	3,500	$57.84	—	—	—	—	16,703	$2.11
Put	500	$55.00	—	—	—	—	—	—
3Q19								
Cashless Collar	3,000	$59.17/$75.72	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	20,000	$2.10
Put	500	$55.00	—	—	—	—	—	—
4Q19								
Cashless Collar	3,000	$59.17/$75.72	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	20,000	$2.10
Put	500	$55.00	—	—	—	—	—	—
1Q20								
Swap	3,000	$63.48	—	—	—	—	—	—

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
1Q19								
Cashless Collar	4,656	$51.46/$65.40	7,600	$2.75/$3.22	—	—	—	—
Swap	4,000	$59.16	1,500	$3.13	7,600	$0.67	11,639	$2.20
Put	172	$55.00	—	—	—	—	—	—
2Q19								
Cashless Collar	6,330	$54.51/$68.74	2,505	$2.75/$3.22	—	—	—	—
Swap	3,500	$57.84	—	—	—	—	19,203	$2.15
Put	—	—	—	—	—	—	—	—
3Q19								
Cashless Collar	4,000	$58.13/$75.54	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	22,500	$2.13
Put	—	—	—	—	—	—	—	—
4Q19								
Cashless Collar	4,000	$58.13/$75.54	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	22,500	$2.13
Put	—	—	—	—	—	—	—	—
1Q20								
Swap	3,000	$63.48	—	—	—	—	2,500	$2.40
Collar	2,000	$55.00/$62.00	—	—	—	—	—	—

Bankruptcy Proceedings under Chapter 11

On January 4, 2017, the Company and all of its direct and indirect subsidiaries (collectively, the “Debtors”) filed voluntary petitions under Chapter 11 in the United States Bankruptcy Court for the District of Delaware (the “Bankruptcy Court”). The Debtors received bankruptcy court confirmation of their *Third Amended Joint Prepackaged Plan of Reorganization*, dated April 6, 2017 (the “Plan”), and emerged from bankruptcy on April 28, 2017 (the “Effective Date”). For additional information about our bankruptcy proceedings and emergence, please refer to *Part II, Item 8, Note 15 - Chapter 11 Proceedings and Emergence*.

Upon emergence from bankruptcy, the Company adopted fresh-start accounting and became a new entity for financial reporting purposes. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date, which differed materially from the recorded values of those same assets and liabilities in the Predecessor Company. As a result, our balance sheets and statement of operations subsequent to the Effective Date are not comparable to our balance sheets and statements of operations prior to the Effective Date. For additional information about our application of fresh-start accounting, please refer to *Part II, Item 8, Note 16 - Fresh-Start Accounting*.

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to April 28, 2017. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company on or prior to April 28, 2017. References to "2017 Successor Period" relates to the period of April 29, 2017 through December 31, 2017. References to "2017 Predecessor Period" relate to the period of January 1, 2017 through April 28, 2017. References to "2016 Predecessor Period" relate to the period of January 1, 2016 through December 31, 2016.

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 received from 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 in certain regions. There is also competition between producers of oil and gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state, and local governments; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing, or producing gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect 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 76% of our estimated proved reserves as of December 31, 2018 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2018, the daily NYMEX WTI oil spot price ranged from a high of $77.41 per Bbl to a low of $44.48 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $6.24 per MMBtu to a low of $2.49 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 surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, and regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations. The regulatory burden on the industry can increase the cost of doing business and negatively affect profitability. 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, current regulatory requirements may change, currently unforeseen incidents may occur, or past noncompliance with laws or regulations may be discovered.

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. The intent of these regulations is to promote the efficient recovery of oil and gas reserves while reducing waste and protecting correlative rights. By collaborating with industry's exploration and development operations, these regulations effectively identify where wells can be drilled, 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 and conservation matters, including the handling and disposal of waste materials, air pollution, the size of drilling and spacing units or proration units, the density of wells that may be drilled, and the unitization and pooling of oil and gas properties.

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, regional, state, and local laws and regulations governing safety and health, the discharge of 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 before drilling or other regulated activity commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities that impact threatened or endangered species or that occur in certain areas and on certain lands lying within wilderness, wetlands, frontier, and other protected 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 and natural resource protection and impose substantial liabilities for pollution resulting from operations 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 of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining required air permits can significantly delay the development of certain oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues.

For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. These regulations establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from certain pneumatic controllers and storage vessels. The EPA issued revised rules in 2013 and 2014 in response to requests for reconsideration of portions the 2012 NESHAP rules from industry and the environmental community. In May 2016, the EPA issued New Source Performance Standards ("NSPS") rules focused on achieving additional methane and volatile organic compound reductions from oil and natural gas operations. Among other things, these revisions impose new requirements for leak detection and repair, control requirements for oil well completions, and additional control requirements for gathering, boosting, and compressor stations. EPA proposed further revisions to the NSPS rules on September 11, 2018 intended to roll back parts of the 2016 rules. The proposed revisions address certain technical issues raised in administrative petitions and include proposed changes to, among other things, the frequency for monitoring fugitive emissions at well sites and compressor stations.

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.

On October 1, 2015, EPA finalized its rule lowering the existing 75 part per billion ("ppb") national ambient air quality standard ("NAAQS") for ozone under the CAA to 70 ppb. Also in 2015, the state of Colorado received a bump-up in its existing ozone standard non-attainment status from "marginal" to "moderate." Oil and natural gas operations in ozone non-attainment areas, including in the DM/NFR area, may be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. Based on 2018 air quality monitoring data, the DM/NFR area may be reclassified to "serious" non-attainment on January 1, 2020 because the area does not meet the 2008 NAAQS for 2018. A "serious" classification would trigger significant additional obligations for the state under the CAA and could 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 a 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.

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, comprehensively updated its oil and gas regulations in 2008 and adopted significant additional amendments in 2011, 2013, 2014, 2015, 2016, and 2018. Among other things, the updated and amended regulations require operators to reduce methane emissions associated with hydraulic fracturing, compile and report additional information regarding wellbore integrity, publicly disclose the chemical ingredients used in hydraulic fracturing, increase the minimum distance between occupied structures and oil and gas wells, undertake additional mitigation for nearby residents, implement additional groundwater testing, undertake certain measures to minimize flood risks, and comply with new requirements for the installation and operation of flowlines. In 2014, Colorado enacted legislation to increase the potential sanctions for statutory, regulatory and other violations. Among other things, this legislation and its implementing regulations mandate monetary penalties for certain types of violations, require a penalty to be assessed for each day of violation and significantly increase the maximum daily penalty amount. Colorado has also expanded its inspection and enforcement of staff. In early 2016, Colorado adopted rules imposing additional permitting requirements for certain large scale facilities in urban mitigation areas and additional notice requirements prior to engaging in operations near certain municipalities. Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions of our operations. In 2018, Colorado adopted rules requiring new wells and production facilities to be sited at least 1,000 feet from school facilities and child care centers.

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. Regulated entities are required to come into compliance with these standards by August 29, 2019. 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. As also noted above, in January 2017, the EPA issued a proposed rule to include natural gas processing facilities in the Toxic Release Inventory ("TRI") program. The United States Department of the Interior also finalized a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity, and handling of flowback water; however, on December 29, 2017, the 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 Bureau of Land Management ("BLM") proposed rules related to further controlling the venting and flaring of natural gas on BLM land. On September 28, 2018, the BLM published a final rule that revises the 2016 rules. The new rule, among other things, rescinds 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 have filed challenges to the 2018 rule in the United States District Court for the Northern District of California.

Apart from these ongoing federal and state initiatives, some 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. Legislation has also been introduced in Colorado to increase local control regarding oil and gas development. Although this legislation was not adopted, similar legislation could be enacted in the future. 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 are also considering additional requirements related to seismic safety for hydraulic fracturing activities. A 2015 U.S. Geological Survey report identified eight states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. Any regulation that restricts our ability to dispose of produced waters or increases the cost of doing business could cause 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 you that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations.

Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in 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 Colorado Oil and Gas Conservation Commission (the "COGCC"), as well as other state agencies. On August 22, 2017, Colorado Governor John Hickenlooper announced seven policy initiatives developed during the Colorado's review of oil and gas operations. One rulemaking initiative resulting from Colorado's review was a strengthening of COGCC's flowline regulations and requirements. COGCC finalized the new flowline rules on February 19, 2018. The new rule includes: increased registration requirements, flowline design requirements, integrity management requirements, and leak detection programs, and requirements for abandoned flowlines. 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. Additionally, the COGCC approved rules regarding minimum setbacks, groundwater monitoring, large-scale facilities in urban mitigation areas, and public notice requirements that are intended to prevent or mitigate environmental impacts of oil and gas development and include the permitting of wells. 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. The state of Colorado also created a task force to make recommendations for minimizing land use and other conflicts concerning the location of new oil and gas facilities. In early 2016, COGCC finalized a rulemaking to implement rules applicable to the permitting of large-scale oil and gas facilities in urban mitigation areas and rules requiring operators to register with and provide operational information, including advance notice for certain operations, to municipalities prior to conducting oil and gas operations.

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.

Hazardous substances and waste handling

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these potentially "responsible persons" may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as 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 natural gas and oil exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent 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 requires 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. If the EPA proposes new rulemaking, the 2016 consent decree requires the EPA to take final action on such rules no later than July 15, 2021.

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.

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.

Climate change

Based on EPA findings that emissions of carbon dioxide, methane, and other greenhouse gases ("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 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 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 is ongoing. Depending on an EPA's final rule, 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. The comment period on the proposed rule closed on April 26, 2018. On August 21, 2018, EPA proposed the Affordable Clean Energy ("ACE") rule, which would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE would replace the CPP, and the rulemaking process is ongoing.

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 President Trump has the authority to unilaterally withdraw the United States from the Paris Agreement, it is not clear at this time what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement.

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 adopted a new regulatory definition of “waters of the U.S.” (“WOTUS”), which governs which waters and wetlands are subject to the CWA. In February 2018, the EPA issued a rule that delays the applicability of the new definition of the waters of the United States until 2020. On August 16, 2018, the U.S. District Court for South Carolina found that the EPA and the Corps failed to comply with the Administrative Procedure Act and struck the 2018 rule that attempted to delay the applicability date of the 2015 rule. Other district courts, however, have issued rulings temporarily enjoining the applicability of the 2015 rule itself. On December 11, 2018, the EPA and the Corps issued a proposed new rule that would differently revise the definition of “waters of the United States” and essentially replace both the 1986 rule and the 2015 rule. According to the agencies, the proposed new rule is “intended to increase CWA program predictability and consistency by increasing clarity as to the scope of ‘waters of the United States’ federally regulated under the Act.” If finalized, this new definition of “waters of the United States” will likely be challenged and sought to be enjoined in federal court. Until that time, regulations are being implemented as they were prior to August 2015. Additionally, in June 2016, the EPA finalized new CWA pretreatment standards that would prevent onshore unconventional oil and natural gas wells from discharging wastewater pollutants to publicly-owned treatment facilities. Regulated entities are required to come into compliance with these pretreatment standards by August 29, 2019.

Endangered Species Act

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

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (“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 agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an Environmental Assessment to evaluate the potential direct, indirect, and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. The vast majority of our exploration and production activities are not on federal lands. This environmental impact assessment process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects on federal lands. Authorizations under NEPA also are subject to protest, appeal, or litigation, which can delay or halt projects.

Oil Pollution Act

The Oil Pollution Act of 1990 (“OPA”) establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A “responsible party” under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the

U.S. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction, or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

Employees

As of December 31, 2018, we had 144 employees, of which 20 full-time employee equivalents were dedicated to our Rocky Mountain Infrastructure, LLC operations. We also utilized the services of numerous independent contractors to perform various field and other services. Our future success will depend partially on our ability to attract, retain, and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

Offices

As of December 31, 2018, 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. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

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

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

Item 1A. ***Risk Factors.***

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

Risks Related to Our Business

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

The price we receive for our oil and, to a lesser extent, natural gas and NGLs, heavily influences our revenue, profitability, cash flows, liquidity, access to capital, present value and quality of our reserves, the nature and scale of our operations, and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. In recent years, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 76% of our estimated proved reserves as of December 31, 2018 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 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, 2018, the daily New York Mercantile exchange ("NYMEX") WTI oil spot price ranged from a high of $77.41 per Bbl to a low of $44.48 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $6.24 per MMBtu to a low of $2.49 per MMBtu. As of February 25, 2019, the daily NYMEX WTI oil spot price and NYMEX natural gas HH spot price was $55.33 per Bbl and $2.84 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 Current Credit Facility 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.

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

Oil and natural gas prices are volatile. 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 Current 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 Current 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 approximately 59% of our guided 2019 production hedged. To the extent that the price of oil and natural gas decline below current levels, our results of operations and financial condition would be materially adversely impacted. See the *Derivative Activity* section in Part I, Item I of this Annual Report on Form 10-K for a summary of our hedging activity.

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

Oil, natural gas, and NGL prices have significantly declined since mid-2014 and have not regained previous highs. This depressed price environment resulted in a reduction in our available liquidity until we negotiated a new reserve based credit facility in late 2018. However, we have substantial capital needs, including in connection with the continued development of our oil and gas assets. We may not have the ability to generate sufficient cash flows from operations and our credit facility's borrowing base may be reduced in the future. Therefore, we may have insufficient liquidity to meet our anticipated working capital, debt service, and other liquidity needs.

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.

We recently emerged from bankruptcy, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our recent emergence from the Chapter 11 bankruptcy proceedings could adversely affect our business and relationships with customers, employees, and suppliers. Due to uncertainties, many risks exist, including the following:

- key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- the ability to renew existing contracts and compete for new business may be adversely affected;
- the ability to attract, motivate, and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; and
- competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition, and reputation. There can be no assurance that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of our reorganization plan and the transactions contemplated thereby and the adoption of fresh-start accounting.

In connection with the disclosure statement we filed with the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"), and the hearing to consider confirmation of our Third Amended Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code, dated April 6, 2017 (the "reorganization plan"), we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of the reorganization plan and our ability to continue operations upon emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic, and competitive risks, and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

In addition, upon emergence from bankruptcy, we adopted fresh-start accounting, as a consequence of which our assets and liabilities were adjusted to fair value and our accumulated deficit was restated to zero. Accordingly, our future financial conditions and results of operations following our emergence are not comparable to the financial condition or results of operations reflected in our historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

The Current 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 Current 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 Current 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 Current 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 would not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. As of 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 Current Credit Facility. Our ability to comply with the financial ratios and financial condition tests under the Current 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 Current Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.

Beginning on May 1, 2019, the borrowing base under the Current Credit Facility will be 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. Upon a redetermination, we could be required to repay a portion of our bank debt to the extent our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder requiring us to negotiate renewals, arrange new financing, or sell significant assets, all of which could have a material adverse effect on our business and financial results.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development, and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, 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 infastructure 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, 2018, 2017 and 2016.

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 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, 2018, 2017, and 2016, 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 expenditures;
- 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 mid-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;
- fracture stimulating the planned number of stages;
- 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.

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

The hydraulic fracture stimulation process on which we depend to produce commercial quantities of oil and natural gas requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water (including during times of droughts), or to dispose of or recycle the water used in our operations, could adversely impact our operations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of oil and natural gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, and all of which could have an adverse effect on our operations and financial condition.

The unavailability or high cost of additional drilling rigs, pressure pumping fleets, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, pressure pumping fleets, equipment, supplies, personnel, or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition, or results of operations and may lead to reduced liquidity and the inability to pay our liabilities as they come due.

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

Our exploration, development, and exploitation activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production, and acquisition of oil and natural gas reserves. At this time, we intend to finance future capital expenditures primarily through cash flows provided by operating activities and borrowings under the Current 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 Current 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 production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under the Current 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 Current 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.

Increased costs of capital could adversely affect our business.

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

Concentration of our operations in 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.

During the first quarter of 2018, we established a plan to sell all of our assets within our Mid-Continent region and North Park Basin, at which point they were deemed held for sale. We sold our North Park Basin assets on March 9, 2018. On August 6, 2018, we divested of our assets within the Dorcheat and Macedonia Fields in southern Arkansas.

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

Specifically in Colorado, anti-development activity has both increased and become more effective in recent years. For example, 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. This initiative was rejected by voters, but if it had been successful, it may have resulted in dramatically reducing the area of future oil and gas development in Colorado. More recently, the same anti-development activists filed a lawsuit challenging the constitutionality of the statutory pooling provision of the Colorado Oil and Gas Act. If successful, the lawsuit could result in significantly reducing the area of oil and gas development in the state. Additionally, Colorado’s newly elected governor, Jared Polis, has vowed to increase local governmental control over oil and gas development in the state, which could serve to increase anti-development initiatives in certain communities. 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.

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

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

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

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production getting to market. The marketability of our oil and natural gas and production, particularly from our wells located in the Wattenberg Field, depends in part on the availability, proximity, and capacity of gathering, processing, pipeline, trucking, and rail systems. The amount of oil and natural gas that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, maintenance, weather, field labor issues, or disruptions in service. Curtailments and disruptions in these systems may last from a few days to several months. Any significant curtailment in gathering, processing, or pipeline system capacity, significant delay in the construction of necessary facilities, or lack of availability of transport, would interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations, and the expected results of our development program.

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 58% of our total proved reserves were classified as proved undeveloped as of December 31, 2018. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate or that may be available to us. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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

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

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 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 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.

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.

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

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including uncertainty in the level of reserves, the availability of capital to us and other participants, seasonal conditions, regulatory approvals, oil, 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.

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 the filing date of this report, approximately 10,739 net acres of our properties were not held by production. For these properties, if production in paying quantities is not established on units containing these leases during the next year, then approximately 432 net acres will expire in 2019, approximately 2,959 net acres will expire in 2020, and approximately 1,429 net acres will expire in 2021 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.

We may incur losses as a result of title deficiencies.

The existence of a title deficiency can diminish the value of an acquired leasehold interest and can adversely affect our results of operations and financial condition. Title insurance covering mineral leasehold interests is not generally available. As is industry standard, we may rely upon a land professional's careful examination of public records prior to purchasing or leasing a mineral interest. Once a mineral or leasehold interest has been acquired, we typically defer the expense of obtaining further title verification by a practicing title attorney until approval to drill a well that includes the acquired mineral interest is required. We perform the necessary curative work to correct deficiencies in the marketability of the title, and we have compliance and control measures to ensure any associated business risk is approved by the appropriate Company authority. In cases involving more serious title deficiencies, all or part of a mineral or leasehold interest may be determined to be invalid or unleased, and, as a result, the target area may be deemed to be undrillable until owners can be contacted and curative measures performed to adequately perfect title. In other cases, title deficiencies may result in our failure to have paid royalty owners correctly. Certain title deficiencies may also result in litigation to quiet the title and effectively agree or render a decision upon title ownership.

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 that impact threatened or endangered species or that occur on certain lands lying within wilderness, wetlands, and other sensitive or protected areas; the application of specific health and safety criteria to protect 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 and water, the underground injection or other disposal of our wastes, the use and disposition of hydraulic fracturing fluids, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable for the full cost of removing or remediating contamination, regardless of whether we were at fault, and even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws 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. 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. In addition, voters in Colorado have proposed or advanced ballot initiatives restricting or banning oil and gas development in Colorado. Because a substantial portion of our operations and reserves are 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 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 you 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 growing belief that human-caused (anthropogenic) emissions of greenhouse gases ("GHGs") may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and 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 "Quad O" 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. Cap and trade programs typically work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of available allowances reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or 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.

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

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend heavily on our financial resources and ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas, and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical, and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for, and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand unsuccessful drilling attempts and sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel, and raising additional capital, which could have a material adverse effect on our business.

If we fail to retain our existing senior management or technical personnel or attract qualified new personnel, such failure could adversely affect our operations. The volatility in commodity prices and business performance may affect our ability to retain senior management, and the loss of these key employees may affect our business, financial condition, and results of operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management, technical personnel, or any of the vice presidents of the Company, could have a material adverse effect on our operations or strategy. The volatility in commodity prices and our business performance may affect our ability to incentivize and retain senior management or key employees. Competition for experienced senior management, technical, and other professional personnel remains strong.

If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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 collars and fixed-price swaps. 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.

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, which were $38.3 million at December 31, 2018, joint interest and other receivables of $47.6 million at December 31, 2018, and the sale of our oil, natural gas, and NGLs production of $31.8 million in receivables at December 31, 2018, 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, 2018, sales to NGL Crude Logistics, LLC comprised 66% of our total sales. Beginning in 2017 and continuing for seven years, 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.

In February 2019, the Company was sent a notice of intent to sue ("NOI") letter by WildEarth Guardians ("WEG"), alleging failure to obtain required permits under the federal Clean Air Act before constructing and operating well production facilities in the ozone non-attainment area around the Denver Metropolitan and North Front Range of Colorado, among other things. The NOI letter appears to challenge long-established federal and state regulations and policies for permitting the construction and initial operation of upstream oil and gas production facilities in Colorado and elsewhere under the Clean Air Act and state counterpart statutes. Because the allegations made in the NOI letter are based on novel and unprecedented interpretations of complex federal and state air quality laws and regulations, it is not possible for the Company to determine at this time whether the allegations have merit or will lead to actual suit by WEG against the Company.

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

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

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

Any such changes in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations, and cash flow.

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

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

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing, and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. Pipelines, refineries, power stations, and distribution points for both fuels and electricity are becoming more interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. Our technologies, systems, networks, and those of our vendors, suppliers, and other business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, 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

We do not 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.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, our Current Credit Facility places certain restrictions on our ability to pay dividends. Consequently, our stockholders' only likely opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the stockholders sell their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the stockholders paid.

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 2018 calendar year, the sales price of our common stock ranged from a low of $18.41 per share to a high of $40.38 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 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 to issue preferred stock without stockholder approval. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

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

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

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, except as set forth below.

During 2015, the Company voluntarily instigated an internal audit of its storage tank facilities located in the Wattenberg Field (the "Audit"). The purpose of the Audit was to determine compliance with applicable air quality regulations. Based on the results of the Audit, the Company self-reported in December 2015 and January 2016 several potential noncompliance issues to the Colorado Department of Public Health and Environment ("CDPHE") under Colorado's Environmental Audit Privilege and Immunity Law (the "Environmental Audit Law"). Independently, in October 2015, CDPHE issued to the Company a compliance advisory (the "Compliance Advisory") for certain facilities that was closely related to the matters voluntarily disclosed as a result of the Audit.

The Company vigorously defended against the CDPHE allegations of violation while also cooperating with CDPHE in its investigation and firmly asserting the Company's right to civil penalty immunity for voluntarily disclosed violations under the Environmental Audit Law. In February 2017, following further interaction between the CDPHE and the Company, the CDPHE proposed settlement terms under which the Company would be required to pay an administrative penalty and perform certain mitigation projects and adopt certain procedures and processes addressing the monitoring, reporting, and reduction of emissions with respect to the Company's storage tank facilities in the Wattenberg Field.

Following negotiations with CDPHE, on October 3, 2017, the Company agreed to a Compliance Order on Consent (the "COC") with the CDPHE. As part of the COC, the Company was required to pay a $0.2 million penalty. Additionally, as further required by the COC, the Company will perform certain mitigation projects and adopt certain procedures and processes addressing the monitoring, reporting, and control of air emissions with respect to the Company's storage tank facilities in the Wattenberg Field. The COC further sets forth compliance requirements and criteria for continued operations and contains provisions regarding record-keeping, modifications to the COC, circumstances under which the COC may terminate with respect to certain wells and facilities, and the sale or transfer of operational or ownership interests covered by the COC. In order to be in compliance, the Company incurred $1.2 million and $0.7 million in 2018 and 2017, respectively, and currently anticipates spending $3.1 million for 2019 through 2022. The COC can be terminated after four years with a showing of substantial compliance and CDPHE approval.

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 Company estimates that $2.3 million of the reimbursement is due to the Company's associated interest owners as shown in the accounts payable and accrued expenses line item in the accompanying balance sheets. The remaining net settlement amount of $5.1 million is presented as a reimbursement in the accompanying statements of operations within the severance and ad valorem taxes line item. This net settlement amount will be further reduced to reflect the reimbursement to the State of Colorado of a certain amount of severance tax credits received in connection with ad valorem taxes historically paid by the Company.

In February 2019, the Company was sent a notice of intent to sue ("NOI") letter by WildEarth Guardians ("WEG"), an environmental non-governmental organization, alleging failure to obtain required permits under the federal Clean Air Act before constructing and operating well production facilities in the ozone non-attainment area around the Denver Metropolitan and North Front Range of Colorado, among other things. The Company is one of seven operators in the Wattenberg Field to receive such an NOI letter from WEG, and these letters appear to challenge long-established federal and state regulations and policies for permitting the construction and initial operation of upstream oil and gas production facilities in Colorado and elsewhere under the Clean Air Act and state counterpart statutes. Because the allegations made in the NOI letters are based on novel and unprecedented interpretations of complex federal and state air quality laws and regulations, it is not possible for the Company to determine at this time whether the allegations have merit or will lead to actual suit by WEG against the Company and other operators, but the Company will vigorously defend against such allegations if sued, and will coordinate as much as possible with state and federal permitting authorities to maintain the validity of its current and future air permits for such facilities.

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 25, 2019, there were approximately 34 registered holders of our common stock.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our Current 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 anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the Current Successor Period.

	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
January 1, 2018 - March 31, 2018	37	$	27.89	—	—
April 1, 2018 - June 30, 2018	24,013	$	30.56	—	—
July 1, 2018 - September 30, 2018	1,941	$	32.67	—	—
October 1, 2018 - December 31, 2018	—	$	—	—	—
Total	25,991	$	30.71	—	—

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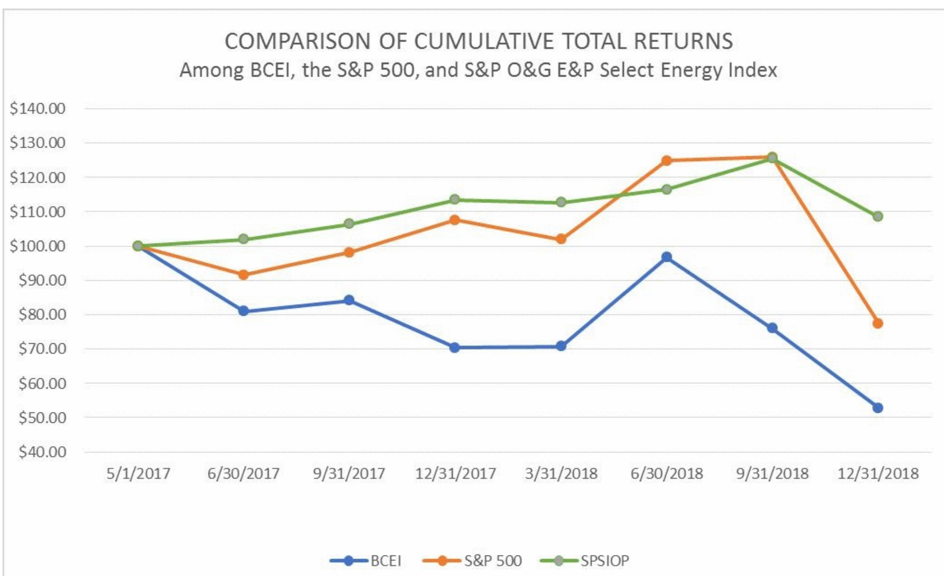
(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced plan or program to repurchase shares of our common stock, 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, 2018.

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, 2018. The graph assumes that $100 was invested on May 1, 2018 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. ***Selected Financial Data.***

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

The following tables set forth selected historical financial data of the Company for the period indicated (in thousands, except per share amounts).

	Predecessor				Successor	
	Year Ended December 31, 2014	Year Ended December 31, 2015	Year Ended December 31, 2016	January 1, 2017 through April 28, 2017	April 29, 2017 through December 31, 2017	Year Ended December 31, 2018
Statement of Operations Data:						
Total operating net revenues (1)	$ 558,633	$ 292,679	$ 195,295	$ 68,589	$ 123,535	$ 276,657
Income (loss) from operations (1)	(47,506)	(907,444)	(129,110)	(1,600)	12,009	112,394
Net income (loss)	20,283	(745,547)	(198,950)	2,660	(5,020)	168,186
Basic net income (loss) per common share	$ 0.50	$ (15.57)	$ (4.04)	$ 0.05	$ (0.25)	$ 8.20
Basic weighted-average common shares outstanding	40,139	47,874	49,268	49,559	20,427	20,507
Diluted net income (loss) per common share	$ 0.49	$ (15.57)	$ (4.04)	$ 0.05	$ (0.25)	$ 8.16
Diluted weighted-average common shares outstanding	40,290	47,874	49,268	50,971	20,427	20,603
Selected Cash Flow Data:						
Net cash (used for) provided by operating activities	$ 339,958	$ 226,023	$ 14,563	$ (19,884)	$ 27,574	$ 116,598
Net cash used in investing activities	(837,232)	(452,573)	(67,460)	(6,022)	(82,641)	(164,376)
Net cash (used for) provided by financing activities	$ 319,276	$ 245,307	$ 112,062	$ 15,406	$ (2,398)	$ 47,998
Sales Volumes:						
Oil (MBbls)(2)	5,618.7	6,072.3	4,309.9	1,068.5	2,012.7	3,840.8
Natural gas (MMcf)(3)	15,395.8	14,551.1	12,231.3	3,336.1	5,938.0	8,591.2
Natural gas liquids (MBbls)	396.3	1,821.9	1,587.0	449.0	762.4	1,141.2
Average Sales Price (before derivatives):						
Oil (MBbls)(2)	$ 81.95	$ 40.95	$ 35.31	$ 48.29	$ 47.18	$ 59.38
Natural gas (MMcf)(3)	$ 5.11	$ 1.77	$ 1.76	$ 2.57	$ 2.29	$ 2.45
Natural gas liquids (MBbls)	$ 49.14	$ 9.49	$ 12.39	$ 17.52	$ 18.38	$ 22.46
Average Sales Price (after derivatives):						
Oil (MBbls)	$ 84.00	$ 62.07	$ 39.57	$ 48.29	$ 46.44	$ 54.77
Natural gas (MMcf)	$ 5.16	$ 1.95	$ 1.76	$ 2.57	$ 2.29	$ 2.39
Natural gas liquids (MBbls)	$ 49.14	$ 9.49	$ 12.39	$ 17.52	$ 18.38	$ 22.46
Expense per BOE:						
Lease operating expense and gas plant and midstream operating expense	$ 8.44	$ 7.40	$ 7.12	$ 8.04	$ 9.09	$ 7.11
Severance and ad valorem taxes	$ 5.88	$ 1.81	$ 1.93	$ 2.73	$ 2.55	$ 2.96
Depreciation, depletion, and amortization	$ 26.66	$ 23.73	$ 14.01	$ 13.54	$ 5.66	$ 6.53
General and administrative	$ 9.51	$ 6.81	$ 9.71	$ 7.28	$ 11.34	$ 6.62

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

(2) Crude oil sales excludes $0.6 million, $0.2 million, $0.1 million, $0.5 million, and $0.2 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, 2016 Predecessor Period, and 2015 Predecessor Period, respectively.

(3) Natural gas sales excludes $1.3 million, $0.8 million, $0.4 million, $1.5 million, and $0.8 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, 2016 Predecessor Period, and 2015 Predecessor Period, respectively.

The following table sets forth selected historical financial data of the Company as of the period indicated (in thousands).

	Predecessor			Successor	
	As of December 31,				
	2014	2015	2016	As of December 31, 2017	As of December 31, 2018
Balance Sheet Data:					
Cash and cash equivalents	$ 2,584	$ 21,341	$ 80,565	$ 12,711	$ 12,916
Property and equipment, net (excludes assets held for sale)	1,756,477	922,344	1,018,968	774,082	917,974
Oil and gas properties held for sale, net of accumulated depreciation, depletion, and amortization	—	214,922	—	—	—
Total assets	1,990,086	1,259,641	1,134,478	830,371	1,061,534
Debt					
Current Credit Facility	—	—	—	—	50,000
Prior Credit Facility	33,000	79,000	191,667	—	—
Senior Notes, net of unamortized premium and deferred financing costs	791,616	792,666	793,698	—	—
Total stockholders’ equity	$ 740,071	$ 209,407	$ 19,061	$ 688,334	$ 863,913
Estimated Proved Reserves:					
Oil (MMBbls)	54.7	57.4	50.1	52.9	64.4
Natural gas (Bcf)	188.6	144.2	138.0	157.7	165.0
Natural gas liquids (MMBbls)	3.4	19.9	17.5	22.8	24.9
Total proved reserves (MMBoe)	89.5	101.3	90.7	102.0	116.8

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

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. We intend to continue to develop our reserves and increase production through drilling and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives. The majority of our revenues are generated through the sale of oil, natural gas, and natural gas liquids production.

Financial and Operating Results

Our 2018 financial and operational results include:

- Wattenberg Field lease operating expense decreased 18% on a per Boe basis for the year ended December 31, 2018 when compared to the same period in 2017;
- Net cash provided by operating activities was $116.6 million as of December 31, 2018;
- Total liquidity of $312.9 million at December 31, 2018, consisting of our year-end cash balance plus funds available under the Current Credit Facility;
- Wattenberg Field sales volumes increased by 24% for the year ended December 31, 2018 when compared to the same period in 2017;
- Rapidly improving well performance yielded over 1,000 SRL equivalent economic drilling locations in Wattenberg Field;
- Secured our $750.0 million Current Credit Facility with a borrowing base of $350.0 million on December 7, 2018;
- Wattenberg Field proved reserves of 116.8 MMBoe as of December 31, 2018 increased 29% when compared to the same period in 2017;
- PV-10 reserve value increased by 60% to $955.0 million as of December 31, 2018 when compared to the same period in 2017;
- Divested of our Mid-Continent assets for net proceeds of $102.9 million and our North Park Basin assets for minimal net proceeds and full release of all current and future obligations;
- Invested $275.3 million to drill 78 gross wells and turning to sales 42 gross wells;
- Continued to increase our takeaway capacity utilizing four gas processors via eleven interconnects.

Chief Executive Officer Appointment

Effective April 11, 2018, the Company appointed Eric T. Greager as the new President and Chief Executive Officer of the Company. Mr. Greager has over 20 years of experience in the oil and gas industry, including exposure to both the operating and technical aspects of the industry. Mr. Greager, 47, previously served as a Vice President and General Manager at Encana Oil & Gas (USA) Inc. Mr. Greager joined Encana in 2006 and served in various management and executive positions, including as a member of the boards of directors of Encana Procurement Inc. and Encana Oil & Gas (USA) Inc. Mr. Greager previously served on the board of directors of Western Energy Alliance and the board of managers of Hunter Ridge Energy Services. Mr. Greager received his Master's Degree in Economics from the University of Oklahoma and his Bachelor's Degree in Engineering from the Colorado School of Mines.

Chief Financial Officer Appointment

Effective November 13, 2018, the Company appointed Brant H. DeMuth as the new Executive Vice President and Chief Financial Officer and principal financial officer of the Company. Mr. DeMuth previously served as Vice President of Finance and Treasurer at SRC Energy Inc. from October 2014 until November 2018. Prior to joining SRC Energy, Mr. DeMuth served as Interim Chief Financial Officer of DJ Resources, LLC from August 2013 to September 2014 and as Executive Vice President of Strategy and Corporate Development of Gevo, Inc. from June 2011 to May 2013. Mr. DeMuth currently serves on the University of Northern Colorado's Monfort College of Business Dean's Leadership Council. Mr. DeMuth is a Chartered Financial Analyst and received his M.B.A. in Oil and Gas Finance from the University of Denver and his B.S. in Business Administration from Colorado State University.

2019 Capital Budget

The Company's 2019 capital budget of $230.0 to $255.0 million assumes a continuous one-rig development pace. The drilling and completion portion of the budget is expected to be approximately $210.0 million to $220.0 million, which will support drilling 59 gross wells and turning to sales 45 gross wells. Included in the drilling completion budget is $15.0 million for non-operated capital. Of the wells planned to be completed, 16 are XRL wells, five are MRL wells, and 24 are SRL wells. The remaining 2019 capital budget of $20.0 million to $35.0 million is to support infrastructure and leasehold costs. Actual capital expenditures could vary significantly based on, among other things, market conditions, commodity prices, drilling and completion costs, well results, and changes in the borrowing base under our Current Credit Facility.

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 Company conducted standard business operations throughout the bankruptcy proceedings and during the application of fresh-start accounting, resulting in specific financial statement line items following normal course of business trends. The trends associated with the non-impacted financial statement line items are explained throughout the results of operations and include revenues, lease operating expense, gas plant and midstream operating expense, severance and ad valorem taxes, and exploration expense. The financial statement line items that were specifically impacted by the bankruptcy proceedings and application of fresh-start accounting are discussed within the confines of the presented periods and include depreciation, depletion, and amortization, general and administrative expense, interest expense, and reorganization items, net.

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to April 28, 2017. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company on or prior to April 28, 2017. Throughout this Management's Discussion and Analysis, the Company refers to the 2017 annual period which is comprised of both Successor and Predecessor periods. References to "Current Successor Period" relate to the year ended December 31, 2018. References to "2017 Successor Period" relate to the period of April 29, 2017 through December 31, 2018. References to the "2017 Predecessor Period" and "2016 Predecessor Period" relate to the periods of January 1, 2017 through April 28, 2017 and January 1, 2016 through December 31, 2016, respectively. For additional information about our bankruptcy proceedings and emergence, please refer to *Part II, Item 8, Note 15 - Chapter 11*. For additional information about our application of fresh-start accounting, please refer to *Part II, Item 8, Note 16 - Fresh-Start Accounting*.

The table below presents revenues, sales volumes, and average sales prices for the periods indicated (in thousands, except per Boe amounts):

	Successor		Predecessor
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Operating Revenues:			
Crude oil sales(1)	$ 228,075	$ 94,956	$ 51,593
Natural gas sales(2)	21,022	13,605	8,584
Natural gas liquids sales	25,627	14,012	7,867
Product revenue	$ 274,724	$ 122,573	$ 68,044
Sales Volumes:			
Crude oil (MBbls)	3,840.8	2,012.7	1,068.5
Natural gas (MMcf)	8,591.2	5,938.0	3,336.1
Natural gas liquids (MBbls)	1,141.2	762.4	449.0
Crude oil equivalent (MBoe)(3)	6,413.8	3,764.8	2,073.5
Average Sales Prices (before derivatives):			
Crude oil (per Bbl)	$ 59.38	$ 47.18	$ 48.29
Natural gas (per Mcf)	$ 2.45	$ 2.29	$ 2.57
Natural gas liquids (per Bbl)	$ 22.46	$ 18.38	$ 17.52
Crude oil equivalent (per Boe)(3)	$ 42.83	$ 32.56	$ 32.82
Average Sales Prices (after derivatives)(4):			
Crude oil (per Bbl)	$ 54.77	$ 46.44	$ 48.29
Natural gas (per Mcf)	$ 2.39	$ 2.29	$ 2.57
Natural gas liquids (per Bbl)	$ 22.46	$ 18.38	$ 17.52
Crude oil equivalent (per Boe)(3)	$ 40.00	$ 32.17	$ 32.82

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(1) Crude oil sales excludes $0.6 million, $0.2 million, and $0.1 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, 2017 Successor Period, and the 2017 Predecessor Period, respectively.

(2) Natural gas sales excludes $1.3 million, $0.8 million, and $0.4 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the Current Successor Period, 2017 Successor Period, and the 2017 Predecessor Period, respectively.

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

(4) The derivatives economically hedge the price we receive for crude oil. For the Current Successor Period, the derivative cash settlement loss for oil and natural gas was $17.7 million and $0.5 million, respectively, and the derivative cash settlement loss for oil was $1.5 million for the 2017 Successor Period. Please refer to *Part II, Item 8, Note 13 - Derivatives* for additional disclosures.

Operating revenues increased by 44% to $274.7 million for the year ended December 31, 2018 compared to $190.6 million for the year ended December 31, 2017 largely due to a 31% increase in oil equivalent pricing and a 10% increase in sales volumes. The increased volumes are a direct result of the Company increasing the pace and efficiency of its Wattenberg development program during 2018. During the period from January 1, 2018 through December 31, 2018, we turned to sales 34.4 net operated wells in the Rocky Mountain region. In addition to the overall increase of operational activity, there was an increase of $9.7 million related to the adoption of ASC 606, which caused certain revenues to be presented on a gross basis compared to a historical net presentation. Please refer to *Part II, Item 8, Note 2 - Revenue Recognition* for additional disclosures.

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

	Successor		Predecessor
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017
Operating Expenses:			
Lease operating expense	$ 34,825	$ 25,862	$ 13,128
Gas plant and midstream operating expense	10,788	8,341	3,541
Gathering, transportation, and processing	9,732	—	—
Severance and ad valorem taxes	18,999	9,590	5,671
Exploration	291	3,745	3,699
Depreciation, depletion and amortization	41,883	21,312	28,065
Abandonment and impairment of unproved properties	5,271	—	—
Unused commitments	21	—	993
General and administrative expense	42,453	42,676	15,092
Operating expenses	$ 164,263	$ 111,526	$ 70,189
Selected Costs ($ per Boe):			
Lease operating expense	$ 5.43	$ 6.87	$ 6.33
Gas plant and midstream operating expense	1.68	2.22	1.71
Gathering, transportation, and processing	1.52	—	—
Severance and ad valorem taxes	2.96	2.55	2.73
Exploration	0.05	0.99	1.78
Depreciation, depletion and amortization	6.53	5.66	13.54
Abandonment and impairment of unproved properties	0.82	—	—
Unused commitments	—	—	0.48
General and administrative expense	6.62	11.34	7.28
Operating expenses	$ 25.61	$ 29.63	$ 33.85
Operating expenses, excluding impairments and abandonments and unused commitments	$ 24.79	$ 29.63	$ 33.37

Lease operating expense. Our lease operating expense decreased $4.2 million or 11%, to $34.8 million for the year ended December 31, 2018 from the combined 2017 Successor and Predecessor Periods of $39.0 million, and decreased on an equivalent basis to $5.43 per Boe from $6.68 per Boe. The decrease is primarily due to the sale of our Mid-Continent assets on August 6, 2018. The Company has also taken measures to decrease its lease operating expense, in conjunction with an increase in production, which caused the per Boe metric to further decrease. During 2018, the Company experienced decreases in its well servicing and maintenance costs of $3.2 million and $0.7 million, respectively.

Gas plant and midstream operating expense. Our gas plant and midstream operating expense decreased $1.1 million to $10.8 million for the year ended December 31, 2018 from $11.9 million for the combined 2017 Successor and Predecessor Periods, and decreased on an equivalent basis to $1.68 per Boe from $2.04 per Boe. The decrease is primarily due to the sale of our Mid-Continent assets on August 6, 2018.

Gathering, transportation, and processing. As noted in the operating revenues section above, the increase in gathering, transportation, and processing expense during the year ended December 31, 2018 to $9.7 million is related to the Company's adoption of ASC 606 during 2018, which caused certain revenues to be shown gross, with the related expenses recorded in this line item. Please refer to *Part II, Item 8, Note 2 - Revenue Recognition* for additional disclosures.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased by 24% from $15.3 million for the combined 2017 Successor and Predecessor Periods to $19.0 million for the year ended December 31, 2018. Severance and ad valorem taxes primarily correlate to revenue. Revenues increased by 44% for the year ended December 31, 2018 when compared to the same period in 2017. The Company received a net ad valorem tax settlement of $5.1 million during the fourth quarter of 2018, which reduced this line item. Please refer to *Part II, Item 8, Note 8 - Commitments and Contingencies* for additional discussion on the settlement.

Exploration. Our exploration expense decreased $7.1 million to $0.3 million for the year ended December 31, 2018 from $7.4 million for the combined 2017 Successor and Predecessor Periods. During the year ended December 31, 2018, we incurred $0.3 million in delay rentals. During the combined 2017 Successor and Predecessor Periods, we paid $3.8 million in delay rentals and incurred $2.9 million on abandoned well projects and $0.7 million in geological and geophysical expenses.

Depreciation, depletion, and amortization. Our depreciation, depletion, and amortization expense per Boe was $6.53, $5.66, and $13.54 for the year ended December 31, 2018, 2017 Successor Period, and 2017 Predecessor Period, respectively. Together, the year ended December 31, 2018 and the 2017 Successor Period (collectively, the “Successor Periods”) reflect the $310.6 million fair value downward adjustment to the depletable asset base upon adoption of fresh-start accounting. The increase in depreciation, depletion, and amortization during the Current Successor Period when compared to the 2017 Successor Period primarily correlates to an increase in capital expenditures.

Abandonment and impairment of unproved properties. During the year ended December 31, 2018, abandonment and impairment of unproved properties of $5.3 million was due to the standard annual amortization of our emergence leases that were not held by production at the time of our emergence. There were no abandonment and impairment of unproved properties during the 2017 Successor and Predecessor Periods. Please refer to *Part II, Item 8, Note 1 - Summary of Significant Accounting Policies* for additional discussion on our impairment policy and practices.

Unused commitments. There were immaterial amounts of unused commitments during the year ended December 31, 2018. No amounts of unused commitments were incurred during the 2017 Successor Period. During the 2017 Predecessor Period, we incurred $1.0 million in unused commitment fees on a water supply contract in the Wattenberg Field.

General and administrative expense. Our general and administrative expense per Boe was $6.62, $11.34, and $7.28 for the year ended December 31, 2018, 2017 Successor Period, and 2017 Predecessor Period, respectively. The 2017 Successor Period reflects a one-time cash and non-cash $9.6 million, or $2.55 per Boe, severance charge primarily related to the Company's former Chief Executive Officer's separation from the Company. The remaining decrease in expense for the year ended December 31, 2018 when compared to the combined 2017 Successor and Predecessor Periods was due to decreases in consultant restructuring fees of $5.4 million and wages and benefits of $2.7 million, partially offset by increases in employee bonuses of $1.6 million and professional services of $0.8 million.

Derivative gain (loss). Our derivative gain for the year ended December 31, 2018 was $30.3 million as compared to a loss of $15.4 million for the 2017 Successor Period. We had no derivative contracts during the 2017 Predecessor Period. During the year ended December 31, 2018, we entered into several oil and gas costless collars, puts, and swap contracts. Our derivative gain is primarily due to fair market value adjustments caused by market prices being lower than our contracted hedge prices. Please refer to *Part II, Item 8, Note 13 - Derivatives* for additional discussion.

Interest expense. Our interest expense for the year ended December 31, 2018, the 2017 Successor Period, and the 2017 Predecessor Period was $2.6 million, $0.8 million, and $5.7 million, respectively. During the year ended December 31, 2018, the Company incurred $1.4 million in interest expense associated with its Current and Prior Credit Facilities, commitment fees of $0.9 million, and miscellaneous fees of $0.3 million related to its Current and Prior Credit Facilities. The Company incurred $0.7 million in commitment fees on the available borrowing base under the Prior Credit Facility during the 2017 Successor Period. Interest expense on the Company's Senior Notes was $1.0 million for the 2017 Predecessor Period, with the remaining interest expense relating to the predecessor credit facility. The Company had no outstanding debt during the 2017 Successor Period. Average debt outstanding for the year ended December 31, 2018 and the 2017 Predecessor Period was $26.8 million and $991.7 million, respectively.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The table below presents revenues, sales volumes, and average sales prices for the periods indicated (in thousands, except per Boe amounts):

	Successor	Predecessor	
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Operating Revenues:			
Crude oil sales[1]	$ 94,956	$ 51,593	$ 152,205
Natural gas sales[2]	13,605	8,584	21,470
Natural gas liquids sales	14,012	7,867	19,660
Product revenue	$ 122,573	$ 68,044	$ 193,335
Sales Volumes:			
Crude oil (MBbls)	2,012.7	1,068.5	4,309.9
Natural gas (MMcf)	5,938.0	3,336.1	12,231.3
Natural gas liquids (MBbls)	762.4	449.0	1,587.0
Crude oil equivalent (MBoe)[3]	3,764.8	2,073.5	7,935.5
Average Sales Prices (before derivatives):			
Crude oil (per Bbl)	$ 47.18	$ 48.29	$ 35.31
Natural gas (per Mcf)	$ 2.29	$ 2.57	$ 1.76
Natural gas liquids (per Bbl)	$ 18.38	$ 17.52	$ 12.39
Crude oil equivalent (per Boe)[3]	$ 32.56	$ 32.82	$ 24.36
Average Sales Prices (after derivatives)[4]:			
Crude oil (per Bbl)	$ 46.44	$ 48.29	$ 39.57
Natural gas (per Mcf)	$ 2.29	$ 2.57	$ 1.76
Natural gas liquids (per Bbl)	$ 18.38	$ 17.52	$ 12.39
Crude oil equivalent (per Boe)[3]	$ 32.17	$ 32.82	$ 26.67

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(1) Crude oil sales excludes $0.2 million, $0.1 million, and $0.5 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the 2017 Successor Period, 2017 Predecessor Period, and the 2016 Predecessor Period, respectively.
(2) Natural gas sales excludes $0.8 million, $0.4 million, and $1.5 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the 2017 Successor Period, 2017 Predecessor Period, and the 2016 Predecessor Period, respectively.
(3) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.
(4) The derivatives economically hedge the price we receive for crude oil. For the 2017 Successor Period, the derivative cash settlement loss was $1.5 million and the derivative cash settlement gain was $18.3 million for the 2016 Predecessor Period. Please refer to *Part II, Item 8, Note 13 - Derivatives* for additional disclosures.

Operating revenues decreased by 1% to $190.6 million for the year ended December 31, 2017 compared to $193.3 million for the year ended December 31, 2016, largely due to a 26% decrease in sales volumes offset by a 34% increase in oil equivalent pricing. The decreased volumes were a direct result of the Company suspending drilling and completion activities through the majority of 2016 and the first half of 2017. During the period from December 31, 2016 through December 31, 2017, we turned to sales 10.0 net operated wells in the Rocky Mountain region and no wells in the Mid-Continent region.

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

	Successor	Predecessor	
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Operating Expenses:			
Lease operating expense	$ 25,862	$ 13,128	$ 43,671
Gas plant and midstream operating expense	8,341	3,541	12,826
Severance and ad valorem taxes	9,590	5,671	15,304
Exploration	3,745	3,699	946
Depreciation, depletion and amortization	21,312	28,065	111,215
Impairment of oil and gas properties	—	—	10,000
Abandonment and impairment of unproved properties	—	—	24,692
Unused commitments	—	993	7,686
Contract settlement expense	—	—	21,000
General and administrative expense	42,676	15,092	77,065
Operating expenses	$ 111,526	$ 70,189	$ 324,405
Selected Costs ($ per Boe):			
Lease operating expense	$ 6.87	$ 6.33	$ 5.50
Gas plant and midstream operating expense	2.22	1.71	1.62
Severance and ad valorem taxes	2.55	2.73	1.93
Exploration	0.99	1.78	0.12
Depreciation, depletion and amortization	5.66	13.54	14.01
Impairment of oil and gas properties	—	—	1.26
Abandonment and impairment of unproved properties	—	—	3.11
Unused commitments	—	0.48	0.97
Contract settlement expense	—	—	2.65
General and administrative expense	11.34	7.28	9.71
Operating expenses	$ 29.63	$ 33.85	$ 40.88
Operating expenses, excluding impairments and abandonments, unused commitments and contract settlement expense	$ 29.63	$ 33.37	32.89

Lease operating expense. Our lease operating expense decreased $4.7 million or 11%, to $39.0 million for the 2017 Successor and 2017 Predecessor Periods from $43.7 million for the year ended December 31, 2016, but increased on an equivalent basis from $5.50 per Boe to $6.68 per Boe due to reduced production. The Company eliminated significant amounts of compression and labor costs resulting in a decrease in total compression costs of $4.1 million for the 2017 Successor and Predecessor Period when compared to the same period in 2016.

Gas plant and midstream operating expense. Our gas plant and midstream operating expense decreased $0.9 million to $11.9 million for the 2017 Successor and 2017 Predecessor Period from $12.8 million for the 2016 Predecessor Period, but increased on an equivalent basis from $1.62 per Boe to $2.04 per Boe due to reduced production. Gas plant and midstream operating expense on an aggregate basis was commensurate between the comparable periods.

Severance and ad valorem taxes. Our severance and ad valorem taxes remained constant between the 2017 Successor and 2017 Period and the 2016 Predecessor Period. Severance and ad valorem taxes primarily correlate to revenue. Revenues decreased by 1% for the 2017 Successor and 2017 Predecessor Period when compared to the same period in 2016.

Exploration. Our exploration expense increased $6.5 million to $7.4 million for the 2017 Successor and 2017 Predecessor Period from $0.9 million for the comparable period in 2016. During the 2017 Successor and 2017 Predecessor Period we paid $3.8 million in delay rentals and incurred $2.9 million on abandoned well projects and $0.7 million in geological and geophysical expenses. During the 2016 Predecessor Period, we incurred $0.9 million on abandoned well projects.

Depreciation, depletion, and amortization. Our depreciation, depletion, and amortization expense per Boe was $5.66, $13.54, and $14.01 for the 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period, respectively. The 2017 Successor Period reflects the $310.6 million fair value downward adjustment to the depletable asset base upon adoption of fresh-start accounting.

Impairment of oil and gas properties. There were no impairment of oil and gas properties during the 2017 Successor and 2017 Predecessor Periods. During the 2016 Predecessor Period, we incurred a $10.0 million impairment charge on our Mid-Continent assets based on the most current bid for the assets received during the first quarter of 2016, when they were held for sale. Please refer to *Note 1 - Summary of Significant Accounting Policies* in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion on our impairment policy and practice.

Abandonment and impairment of unproved properties. There were no abandonment and impairment of unproved properties during the 2017 Successor and 2017 Predecessor Periods. During the 2016 Predecessor Period, we incurred an abandonment and impairment of unproved properties charge of $24.7 million due to non-core leases expiring within the Wattenberg Field.

Unused commitments. There were no unused commitments during the 2017 Successor Period. During the 2017 Predecessor Period, we incurred $1.0 million in unused commitment fees on a water supply contract in the Wattenberg Field. During the 2016 Predecessor Period, we incurred unused commitment fees of $7.7 million, made up of $4.3 million water commitment deficiency payments and $3.4 million purchase and transportation deficiency payments. Please refer to *Note 8 - Commitments and Contingencies* in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion.

Contract settlement expense. There were no contract settlement expenses during the 2017 Successor and 2017 Predecessor Periods. During the 2016 Predecessor Period, we incurred a $21.0 million loss to settle our crude oil purchase agreement with Silo Energy, LLC as part of our bankruptcy process. Please see *Note 8 - Commitments and Contingencies* in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion.

General and administrative expense. Our general and administrative expense per Boe was $11.34, $7.28 and $9.71 for the 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period, respectively. The 2017 Successor Period reflects a one-time cash and non-cash $9.6 million or $2.55 per Boe severance charge primarily related to the Company's former Chief Executive Officer's separation from the Company. The 2016 Predecessor Period includes $13.3 million, or $1.68 per Boe, more in advisor fees than the comparable period in 2017. Excluding those two items, the per Boe metrics were commensurate between the periods presented.

Derivative gain (loss). Our derivative loss for the 2017 Successor Period was $15.4 million. We had no derivative contracts during the 2017 Predecessor Period. During the 2017 Successor Period, we entered into several oil and gas costless collar and swap contracts. Our derivative loss was mainly due to fair market value adjustments caused by market prices being higher than our contracted hedge prices. Our derivative loss for the 2016 Predecessor Period was $11.2 million. Due to the Company being in default on the predecessor credit facility, all of these derivative contracts in the 2016 Predecessor Period were terminated during the fourth quarter of 2016. Please see *Note 13 - Derivatives* in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion.

Interest expense. Our interest expense for the 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period was $0.8 million, $5.7 million, and $62.1 million, respectively. Upon filing its petition for Chapter 11, the Company ceased accruing interest expense on its Senior Notes. The Company incurred $0.7 million in commitment fees on the available borrowing base under the successor credit facility during the 2017 Successor Period. Interest expense on the Senior Notes was $1.0 million and $52.3 million for the 2017 Predecessor Period and 2016 Predecessor Period, respectively, with the remaining interest expense relating to the predecessor credit facility. The Company had no outstanding debt during the 2017 Successor Period. Average debt outstanding for the 2017 Predecessor Period and 2016 Predecessor Period was $991.7 million and $1.0 billion, respectively.

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 approximately 54% and 59% of our average 2019 guided production hedged as of December 31, 2018 and as of the filing date of this report, respectively.

As of December 31, 2018, our liquidity was $312.9 million, consisting of cash on hand of $12.9 million and $300.0 million of available borrowing capacity on our Current Credit Facility. As of the date of filing, we had $65.0 million outstanding on our credit facility.

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

	Successor		Predecessor	
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Net cash (used in) provided by operating activities	$ 116,598	$ 27,574	$ (19,884)	$ 14,563
Net cash used in investing activities	(164,376)	(82,641)	(6,022)	(67,460)
Net cash (used in) provided by financing activities	47,998	(2,398)	15,406	112,062
Cash and cash equivalents, and restricted cash	13,002	12,782	70,247	80,747
Acquisition of oil and gas properties	2,892	5,383	445	98
Exploration and development of oil and gas properties	264,231	76,384	5,123	52,344

Cash flows (used in) provided by operating activities

The Current Successor and 2017 Successor Periods include cash receipts and disbursements attributable to our normal operating cycle. The 2017 and 2016 Predecessor Period contained reorganization costs along with our normal operating receipts and disbursements. 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 $267.1 million, $81.8 million, $5.6 million, and $52.4 million for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period, respectively. The fluctuation in cash flows in investing activities is a direct result of the Company's current strategic emphasis on growing operational capability as well as its entrance and emergence from bankruptcy.

Cash flows (used in) provided by financing activities

Net cash provided by financing activities for the Current Successor Period primarily consisted of net draws of $50.0 million on our Current Credit Facility. Net cash used by financing activities for the 2017 Successor Period consisted of employee tax withholdings in exchange for the return of common stock (in conjunction with the vesting of equity awards). Net cash provided by financing activities for the 2017 Predecessor Period consisted of proceeds from the rights offering of $207.5 million net of the $191.7 million repayment to the predecessor credit facility. Net cash provided by financing activities for the year ended December 31, 2016 consisted primarily of net proceeds from the predecessor credit facility of $112.7 million.

Credit facility

Current Credit Facility

On December 7, 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 “Current Credit

Facility”). The Current Credit Facility has an aggregate original commitment amount of $750.0 million and matures on December 7, 2023.

The initial borrowing base in respect of the Current Credit Facility is $350.0 million. The first borrowing base redetermination will occur on May 1, 2019 with subsequent semi-annual redeterminations thereafter.

Borrowings under the Current Credit Facility will bear 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 Current 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 and (d) a one month LIBOR, subject to a 0% LIBOR floor plus a margin of 0.75% to 1.75%, based on the utilization of the Current 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 Current Credit Facility is guaranteed by all wholly owned domestic 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.

The Current Credit Facility contains customary representations and affirmative covenants.

The Current 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, and (xix) sales or discounts of receivables.

The Credit Parties are subject to certain financial covenants under the Current Credit Facility, including, without limitation, tested on the last day of each fiscal quarter, (i) a maximum ratio of the Company’s consolidated indebtedness (subject to certain exclusions) to adjusted EBITDAX of 4.00 to 1.00 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.

As of December 31, 2018, the Company had $50.0 million outstanding under the Current Credit Facility and had the ability to borrow up to the borrowing base of $350.0 million. For more information regarding our debt, please refer to *Part II, Item 8, Note 7 - Long-term Debt.*

As of December 31, 2018, and through the filing date of this report, the Company is in compliance with all credit facility covenants.

Prior Credit Facility

On April 7, 2017, the Company's Plan was confirmed by the Bankruptcy Court, and the Plan became effective on April 28, 2017. Upon emergence from bankruptcy, we (i) executed a credit agreement (the “Prior Credit Facility”) with an initial borrowing base of $191.7 million and maturity date of March 31, 2021 and (ii) issued new common stock as part of the $200.0 million rights offering and the $7.5 million transaction with the ad hoc equity committee in the bankruptcy proceeding. Please refer to *Note 15 - Chapter 11 Proceedings and Emergence* for additional details.

Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2018:

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
			(in thousands)		
Contractual Obligation					
Current Credit Facility[(1)]	50,000	—	—	50,000	—
Interest and fees on Current Credit Facility[(1)]	17,107	3,469	6,938	6,700	—
Delivery commitments[(2)]	136,253	19,580	56,740	59,933	—
Office lease[(3)]	4,242	1,256	2,752	234	—
Asset retirement obligations[(4)]	118,783	—	17,369	6,343	95,071
Total	$ 326,385	$ 24,305	$ 83,799	$ 123,210	$ 95,071

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(1) No scheduled payments exist for the Current Credit Facility, and prepayments can be made without penalty, so long as payment is made on the last day of the interest period. The interest is calculated using the stated rate within the Current Credit Facility for the current outstanding balance, and the commitment fees are based on the fess on the available borrowing base over the periods presented.
(2) The Company has one oil purchase agreement and one operating lease. The calculation on the delivery commitments is based on the minimum gross volume commitment schedule (as defined in the NGL Crude Logistics, LLC agreement) and applicable differential fees. Please refer to *Note 8 - Commitments and Contingencies* for additional discussion on this agreement and for a description of our operating lease.
(3) The Company has subleased a portion of its office lease. The contractual amounts disclosed are presented gross, excluding total sublease income of $1.4 million.
(4) Amounts represent our estimated future retirement obligations on an undiscounted basis. The discounted obligations are recorded as liabilities on our accompanying balance sheets as of December 31, 2018 and 2017. 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 11 - Asset Retirement Obligation*, for additional discussion.

Critical Accounting Policies and Estimates

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

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

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing or expiration of unproved lease acquisition costs are recorded as abandonment or impairment of unproved properties in the statements of operations and comprehensive income (loss) in our consolidated financial statements. Lease acquisition 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

In the current and prior year, our third-party petroleum consultant prepared our estimates of oil and natural gas reserves and associated future net revenues. During 2016, our internal corporate reservoir engineering group prepared, and our third-party petroleum engineering consultant audited 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 internal corporate reservoir engineering group and 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 natural gas liquids are recognized when performance obligations are satisfied at the point control of the product is transferred to the customer. Virtually all of our 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 *Footnote 2 - Revenue Recognition* for more information.

The Company records revenues, net of royalties, discounts, and allowances, as applicable, from the sales of crude oil, natural gas, and NGLs when delivery to the customer has occurred and title has transferred. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company factors in historical performance, quality and transportation differentials, commodity prices, and other factors when deriving revenue estimates. Payment is generally received within 30 to 90 days after the date of production. 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, 2018 and 2017.

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

We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, or future plans to develop acreage and record abandonment and impairment expense for any decline in value. Leases that were not held by production upon emergence from bankruptcy are being amortized over the remainder of those leases.

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

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

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

Asset retirement obligations

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

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.

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 range 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 evenly 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 average annual return on capital employed ("ROCE") for each year during the three-year performance period. Compensation expense associated with PSUs is recognized as general and administrative expense over the performance period.

The fair value of the PSUs is measured at the grant date with 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 PSUs, 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.

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, 2018.

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 increased to 2.2% in 2018 from 1.8% in 2017, which was a decrease from 2.0% in 2016. These changes did not have a material impact on our results of operations for the periods ended December 31, 2018, 2017, and 2016. 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 0.3% and our PV-10 value as of December 31, 2018 would decrease by approximately 23% or $223.1 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 0.4% and our PV-10 value as of December 31, 2018 would increase by approximately 24% or $229.8 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 reduce volatility in our cash flows. We enter into derivative contracts for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only well-capitalized counterparties which have been approved by our Board of Directors.

To the extent that we engage in derivative contracts, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices.

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

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

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

For the oil and natural gas derivatives outstanding at December 31, 2018, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2018 would change our derivative gain by $(15.3) million and $16.1 million, respectively.

We have entered into various types of derivative instruments, including commodity price swaps, cashless collars, and puts to mitigate a portion of our exposure to fluctuations in commodity prices.

Interest Rates

At December 31, 2018 and on the filing date of this report we had $50.0 million and $65.0 million outstanding under our Current Credit Facility, respectively. Borrowings under our Current Credit Facility bear interest at a fluctuating rate that is tied to an adjusted Base Rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. As of December 31, 2018 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. Four lenders under our Current Credit Facility are currently 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. Please refer to the section titled *Principal Customers* under Part I, Item 1 of this Annual Report on Form 10-K for further details about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history, and financial resources of our customers, but we do not require our customers to post collateral.

Marketability of Our Production

The marketability of our production 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 Accounting Firm

Board of Directors and Stockholders
Bonanza Creek Energy, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Bonanza Creek Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2018 and 2017 (Successor), and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for the year ended December 31, 2018 and for the period from April 29, 2017 through December 31, 2017 (Successor) and the period from January 1, 2017 through April 28, 2017 (Predecessor), 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, 2018 and 2017 (Successor), and the results of its operations and its cash flows for the year ended December 31, 2018 and for the period from April 29, 2017 through December 31, 2017 (Successor) and the period from January 1, 2017 through April 28, 2017 (Predecessor), in conformity with accounting principles generally accepted in the United States of America.

We also have 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, 2018, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 27, 2019 expressed an unqualified opinion.

Change in accounting principles
As discussed in Note 1 to the consolidated statements, the Company has changed its method of accounting for revenue from contracts with customers due to the adoption of the new revenue standard using the modified retrospective approach. Our opinion is not modified with respect to this matter.

Basis of presentation
As discussed in Note 1 to the consolidated financial statements, the United States Bankruptcy Court for the District of Delaware entered an order confirming the plan for reorganization on April 7, 2017, and the Company emerged from bankruptcy on April 28, 2017. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with FASB Accounting Standards Codification 852, Reorganizations, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods, as described in Note 1.

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 audits 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 audits 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.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2017.

Oklahoma City, Oklahoma

February 27, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated statements of operations and comprehensive loss, stockholders' equity and cash flows of Bonanza Creek Energy, Inc. and subsidiaries for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of Bonanza Creek Energy, Inc. and subsidiaries' operations and their cash flows for the year ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company suffered a significant deterioration in liquidity during 2016, and filed for bankruptcy under Chapter 11 of the Bankruptcy Code on January 4, 2017. This raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Hein & Associates LLP

Denver, Colorado
March 15, 2017

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

	Successor	
	As of December 31,	
	2018	2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12,916	$ 12,711
Accounts receivable:		
Oil and gas sales	31,799	28,549
Joint interest and other	47,577	3,831
Prepaid expenses and other	4,633	6,555
Inventory of oilfield equipment	3,478	1,019
Derivative asset	34,408	488
Total current assets	134,811	53,153
Property and equipment (successful efforts method):		
Proved properties	719,198	555,341
Less: accumulated depreciation, depletion and amortization	(52,842)	(17,032)
Total proved properties, net	666,356	538,309
Unproved properties	154,352	183,843
Wells in progress	93,617	47,224
Other property and equipment, net of accumulated depreciation of $2,546 in 2018 and $2,224 in 2017	3,649	4,706
Total property and equipment, net	917,974	774,082
Long-term derivative asset	3,864	6
Other noncurrent assets	4,885	3,130
Total assets	$ 1,061,534	$ 830,371
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 6)	$ 79,390	$ 62,129
Oil and gas revenue distribution payable	19,903	15,667
Derivative liability	183	11,423
Total current liabilities	99,476	89,219
Long-term liabilities:		
Credit facility (note 7)	50,000	—
Ad valorem taxes	18,740	11,584
Long-term derivative liability	—	2,972
Asset retirement obligations for oil and gas properties	29,405	38,262
Total liabilities	197,621	142,037
Commitments and contingencies (note 8)		
Stockholders' equity:		
Successor preferred stock, $.01 par value, 25,000,000 shares authorized, none outstanding as of December 31, 2018 and 2017	—	—
Successor common stock, $.01 par value, 225,000,000 shares authorized, 20,543,940 and 20,453,549 issued and outstanding as of December 31, 2018 and 2017, respectively	4,286	4,286
Additional paid-in capital	696,461	689,068
Retained earnings (deficit)	163,166	(5,020)
Total stockholders' equity	863,913	688,334
Total liabilities and stockholders' equity	$ 1,061,534	$ 830,371

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

Table of Contents

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

	Successor		Predecessor	
	For the Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	For the Year Ended December 31, 2016
Operating net revenues:				
Oil and gas sales	$ 276,657	$ 123,535	$ 68,589	$ 195,295
Operating expenses:				
Lease operating expense	34,825	25,862	13,128	43,671
Gas plant and midstream operating expense	10,788	8,341	3,541	12,826
Gathering, transportation, and processing	9,732	—	—	—
Severance and ad valorem taxes	18,999	9,590	5,671	15,304
Exploration	291	3,745	3,699	946
Depreciation, depletion, and amortization	41,883	21,312	28,065	111,215
Impairment of oil and gas properties	—	—	—	10,000
Abandonment and impairment of unproved properties	5,271	—	—	24,692
Unused commitments	21	—	993	7,686
Contract settlement expense	—	—	—	21,000
General and administrative expense (including $7,156, $11,630, $2,116, and $8,892, respectively, of stock-based compensation)	42,453	42,676	15,092	77,065
Total operating expenses	164,263	111,526	70,189	324,405
Income (loss) from operations	112,394	12,009	(1,600)	(129,110)
Other income (expense):				
Derivative gain (loss)	30,271	(15,365)	—	(11,234)
Interest expense	(2,603)	(773)	(5,656)	(62,058)
Gain on sale of properties	27,324	—	—	—
Reorganization items, net (note 16)	—	—	8,808	—
Gain on termination fee	—	—	—	6,000
Other income (loss)	800	(1,267)	1,108	(2,548)
Total other income (expense)	55,792	(17,405)	4,260	(69,840)
Income (loss) from operations before taxes	168,186	(5,396)	2,660	(198,950)
Current income tax benefit (expense) (note 10)	—	376	—	—
Deferred income tax benefit (note 10)	—	—	—	—
Net income (loss)	$ 168,186	$ (5,020)	$ 2,660	$ (198,950)
Comprehensive income (loss)	$ 168,186	$ (5,020)	$ 2,660	$ (198,950)
Basic net income (loss) per common share:	$ 8.20	$ (0.25)	$ 0.05	$ (4.04)
Diluted net income (loss) per common share:	$ 8.16	$ (0.25)	$ 0.05	$ (4.04)
Basic weighted-average common shares outstanding	20,507	20,427	49,559	49,268
Diluted weighted-average common shares outstanding	20,603	20,427	50,971	49,268

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

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-In	Accumulated Earnings	
	Shares	Amount	Capital	(Deficit)	Total
	(in thousands, except share data)				
Balances, January 1, 2016 (Predecessor)	49,754,408	$ 49	$ 806,386	$ (597,028)	$ 209,407
Restricted common stock issued	154,656	2	—	—	2
Restricted common stock forfeited	(120,477)	(1)	—	—	(1)
Restricted stock used for tax withholdings	(127,904)	(1)	(288)	—	(289)
Stock-based compensation	—	—	8,892	—	8,892
Net loss	—	—	—	(198,950)	(198,950)
Balances, December 31, 2016 (Predecessor)	49,660,683	$ 49	$ 814,990	$ (795,978)	$ 19,061
Restricted common stock issued	767,848	1	—	—	1
Restricted common stock forfeited	(5,134)	—	—	—	—
Restricted stock used for tax withholdings	(318,180)	(1)	(427)	—	(428)
Fair value of equity issued to existing common stockholders	—	—	(23,410)	—	(23,410)
Stock-based compensation	—	—	2,116	—	2,116
Net income	—	—	—	2,660	2,660
Balances, April 28, 2017 (Predecessor)	50,105,217	$ 49	$ 793,269	$ (793,318)	$ —
Cancellation of Predecessor equity	(50,105,217)	(49)	(793,269)	793,318	—
Balances, April 28, 2017 (Predecessor)	—	$ —	$ —	$ —	$ —
Issuance of Successor equity	20,356,071	4,285	679,836	—	684,121
Balances, April 28, 2017 (Successor)	20,356,071	$ 4,285	$ 679,836	$ —	$ 684,121
Restricted common stock issued	173,200	2	—	—	2
Restricted stock used for tax withholdings	(75,722)	(1)	(2,398)	—	(2,399)
Stock-based compensation	—	—	11,630	—	11,630
Net loss	—	—	—	(5,020)	(5,020)
Balances, December 31, 2017 (Successor)	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 (Successor)	20,543,940	$ 4,286	$ 696,461	$ 163,166	$ 863,913

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)

	Successor		Predecessor	
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Cash flows from operating activities:				
Net income (loss)	$ 168,186	$ (5,020)	$ 2,660	$ (198,950)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	41,883	21,312	28,065	111,215
Non-cash reorganization items	—	—	(44,160)	—
Impairment of oil and gas properties	—	—	—	10,000
Abandonment and impairment of unproved properties	5,271	—	—	24,692
Well abandonment costs and dry hole expense	—	75	2,931	872
Stock-based compensation	7,156	11,630	2,116	8,892
Amortization of deferred financing costs and debt premium	30	—	374	3,180
Derivative (gain) loss	(30,271)	15,365	—	11,234
Derivative cash settlements	(18,160)	(1,464)	—	18,333
Gain on sale of oil and gas properties	(27,324)	—	—	—
Inventory write-offs	248	1,758	—	4,390
Other	(3,559)	11	18	(323)
Changes in current assets and liabilities:				
Accounts receivable	(46,988)	(4,477)	(6,640)	35,282
Prepaid expenses and other assets	2,214	(1,979)	963	(1,838)
Accounts payable and accrued liabilities	19,953	(8,470)	(5,880)	(11,616)
Settlement of asset retirement obligations	(2,041)	(1,167)	(331)	(800)
Net cash provided by (used in) operating activities	116,598	27,574	(19,884)	14,563
Cash flows from investing activities:				
Acquisition of oil and gas properties	(2,892)	(5,383)	(445)	(98)
Exploration and development of oil and gas properties	(264,231)	(76,384)	(5,123)	(52,344)
Proceeds from sale of oil and gas properties	103,134	—	—	—
Payments of contractual obligation	—	—	—	(12,000)
Operating bonds	—	—	—	(2,672)
Additions to property and equipment - non oil and gas	(387)	(874)	(454)	(346)
Net cash used in investing activities	(164,376)	(82,641)	(6,022)	(67,460)
Cash flows from financing activities:				
Proceeds from Current Credit Facility	50,000	—	—	—
Proceeds from Prior Credit Facility	90,000	—	—	—
Payments to Prior Credit Facility	(90,000)	—	—	—
Proceeds from predecessor credit facility	—	—	—	209,000
Payments to predecessor credit facility	—	—	(191,667)	(96,333)
Proceeds from sale of common stock	—	—	207,500	—
Proceeds from exercise of stock options	1,100	—	—	—
Payment of employee tax withholdings in exchange for the return of common stock	(863)	(2,398)	(427)	(289)
Deferred financing costs	(2,239)	—	—	(316)
Net cash provided by (used in) financing activities	47,998	(2,398)	15,406	112,062
Net change in cash, cash equivalents, and restricted cash	220	(57,465)	(10,500)	59,165
Cash and cash equivalents, and restricted cash:				
Beginning of period	12,782	70,247	80,747	21,582
End of period	$ 13,002	$ 12,782	$ 70,247	$ 80,747
Supplemental cash flow disclosure:				

Cash paid for interest	$ 2,582	$ 523	$ 3,509	$ 58,900
Cash paid for reorganization items	$ —	$ —	$ 52,968	$ —
Changes in working capital related to exploration, development and acquisition of oil and gas properties	$ 11,769	$ 16,057	$ 3,360	$ (30,044)

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, 2018, the 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 significant intercompany accounts and transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2018, through the filing date of this report.

On August 6, 2018, the Company sold its equity interests in Bonanza Creek Energy Resources, LLC, which owns 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 4 - Divestitures* for additional discussion.

As of December 31, 2017, the balance sheets include the accounts of the Company and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Bonanza Creek Energy Resources, LLC, Bonanza Creek Energy Upstream LLC, Bonanza Creek Energy Midstream, LLC, Holmes Eastern Company, LLC, and Rocky Mountain Infrastructure, LLC. All significant intercompany accounts and transactions have been eliminated.

On January 4, 2017, the Company and certain of its subsidiaries (collectively with the Company, the "Debtors") filed voluntary petitions (the "Bankruptcy Petitions," and the cases commenced thereby, the "Chapter 11 Cases") under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court") to pursue the Debtors' Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (as proposed, the "Plan"). The Bankruptcy Court granted the Debtors' motion seeking to administer all of the Debtors' Chapter 11 Cases jointly under the caption "In re Bonanza Creek Energy, Inc., et al" (Case No. 17-10015). The Debtors received bankruptcy court confirmation of their Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017 (the "Effective Date"). Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession during a portion of the year ended December 31, 2017. As such, certain aspects of the bankruptcy proceedings of the Company and related matters are described below in order to provide context and explain part of our financial condition and results of operations for the period presented.

Upon emergence from bankruptcy, the Company adopted fresh-start accounting and became a new entity for financial reporting purposes. As a result of the application of fresh-start accounting and the effects of the implementation of the Plan, the Company's condensed consolidated financial statements after April 28, 2017 are not comparable with the financial statements on or prior to April 28, 2017. The Company's condensed consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented after April 28, 2017 and dates prior thereto. Please refer to *Note 16 - Fresh-Start Accounting* for additional discussion.

Subsequent to January 4, 2017 and through the date of emergence, all expenses, gains, and losses directly associated with the reorganization are reported as reorganization items, net in the accompanying consolidated statements of operations and comprehensive income (loss) ("statements of operations").

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to April 28, 2017. References to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company on or prior to April 28, 2017. Throughout these financial statements, the Company refers to the 2017 annual period which is comprised of both Successor and Predecessor periods. References to "Current Successor Period" relate to the year ended December 31, 2018. References to "2017 Successor Period" relate to the period of April 29, 2017 through December 31, 2017. References to the "2017 Predecessor Period" and "2016 Predecessor Period" relate to the periods of January 1, 2017 through April 28, 2017 and January 1, 2016 through December 31, 2016, respectively.

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.

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.

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, depreciation, and amortization ("DD&A") of capitalized costs of proved oil and gas properties are provided for on a field-by-field basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs and anticipated proceeds from salvaging equipment.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property is written down to fair value. The factors used to determine fair value are subject to the Company's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows on all developed proved reserves and risk adjusted probable and possible reserves, net of estimated operating and development costs, future commodity pricing based on our 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.

As of December 31, 2018, the Company's gathering assets comprised $120.4 million, $0.9 million, and $0.1 million of proved properties, wells in progress, and unproved properties, respectively, on the accompanying consolidated balance sheets.

Lease acquisition costs are reclassified to proved properties and depleted on a unit-of-production basis once proved reserves have been assigned. The Company assesses its unproved properties periodically for impairment on a property-by-property basis, which requires significant judgment. Leases that were not held by production upon emergence from bankruptcy are being amortized off over the remainder of those leases. 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;
- its evaluation of the current fair market value of acreage; and
- strategic shifts in development areas.

For additional discussion, please refer to *Note 3 - Impairments*.

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

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

Other Property and Equipment

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

Assets Held for Sale

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 *Footnote 4 - Divestitures* for more information.

Revenue Recognition

Sales of oil, natural gas, and natural gas liquids ("NGLs") are recognized when performance obligations are satisfied at the point control of the product is transferred to the customer. Virtually all of our 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 *Footnote 2 - Revenue Recognition* for more information.

The Company records revenues, net of royalties, discounts, and allowances, as applicable, from the sales of crude oil, natural gas, and NGLs when delivery to the customer has occurred and title has transferred. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company factors in historical performance, quality and transportation differentials, commodity prices, and other factors when deriving revenue estimates. Payment is generally received within 30 to 90 days after the date of production. 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, 2018 and 2017.

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 2017, 2016, and 2015 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, 2018, 2017, and 2016, NGL Crude Logistics accounted for 66%, 44%, and 0% of sales, respectively; Lion Oil Trading & Transportation, Inc. accounted for 8%, 18%, and 18% of sales, respectively; and Duke Energy Field Services accounted for 8%, 16%, and 14% of sales, respectively. For the year ended December 31, 2016, Silo Energy, LLC accounted for 50% of sales.

Oil and Gas Derivative Activities

The Company is exposed to commodity price risk related to oil and gas prices. To mitigate this risk, the Company enters into oil and gas forward contracts. The contracts were 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 13 - Derivatives*.

Earnings Per Share

Earnings per basic and diluted share within the Successor Company are calculated under the treasury stock method. Basic net income (loss) per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. Diluted net income per common share is calculated by dividing net income 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, which are measured using the treasury stock method. 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.

Earnings per basic and diluted share within the Predecessor Company were calculated under the two-class method. Pursuant to the two-class method, the Company's unvested restricted stock awards with non-forfeitable rights to dividends are considered participating securities. Under the two-class method, earnings per basic share is calculated by dividing net income available to shareholders by the weighted-average number of common shares outstanding during the period. The two-class method includes an earnings allocation formula that determines earnings per share for each participating security according to undistributed earnings for the period. Net income available to shareholders is reduced by the amount allocated to participating restricted shares to arrive at the earnings allocated to common stock shareholders for purposes of calculating earnings per share. Participating shares are not contractually obligated to share in the losses of the Company, and therefore, the entire net loss is allocated to the outstanding shares. Earnings per diluted share is computed on the basis of the weighted-average number of common shares outstanding during the period plus the dilutive effect of any potential common shares outstanding during the period using the more dilutive of the treasury method or two-class method. For additional discussion, please refer to *Note 14 - Earnings Per Share*.

Stock-Based Compensation

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

Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, trade receivables, trade payables, accrued liabilities, 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.

Recently Issued and Adopted Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued *Update No. 2014-09, Revenue from Contracts with Customers (Topic 606)* Accounting Standards Codification ("ASC") 606 ("ASC 606"). Several additional related updates were issued since that point. In summary, revenue recognition would occur upon the transfer of promised goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. The guidance also requires enhanced financial statement disclosures over revenue recognition and provisions regarding future revenues and expenses under a gross-versus-net presentation.

The standard was required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. The standard is effective for annual reporting periods beginning after December 15, 2017, and interim periods within those annual periods. We adopted the new standard on January 1, 2018, and its adoption did not have a significant impact on our financial statements. Please refer to *Note 2 - Revenue Recognition* for additional discussion.

In January 2016, the FASB issued *Update No. 2016-01 – Financial Instruments - Overall* to require separate presentation of financial assets and financial liabilities by measurement category and form of financial asset on the balance sheet or the accompanying notes to the financial statements. This authoritative guidance is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. We adopted the new standard on January 1, 2018, and its adoption did not have a material impact on our financial statements and disclosures.

Effective January 1, 2017, the Company adopted FASB *Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting*. The objective of this update was to simplify the current guidance for stock compensation. The areas for simplification involve several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This update is effective for the annual periods beginning after December 15, 2016, and interim periods within those annual periods. As of January 1, 2017, and thereafter, the Company did not have excess tax benefits associated with its stock compensation, and therefore, there was no tax impact upon adoption of this standard. In addition, the employee taxes paid on the statement of cash flows when shares were withheld for taxes have already been classified as a financing activity; therefore, there was no cash flow statement impact upon adoption of this standard. This standard allowed companies to elect to account for forfeitures as they occurred or estimate the number of awards that will vest. The Company elected to account for forfeitures as they occur, resulting in a minimal impact upon adoption of this standard.

In August 2016, the FASB issued *Update No. 2016-15 - Classification of Certain Cash Receipts and Cash Payments*, which clarifies the presentation of specific cash receipts and cash payments within the statement of cash flows. This authoritative accounting guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted. We adopted the new standard on January 1, 2018, and its adoption did not have a material impact on our consolidated statements of cash flows (“statements of cash flows”) and related disclosures.

In November 2016, the FASB issued *Update No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash*. This update clarifies how entities should present restricted cash and restricted cash equivalents in the statement of cash flows by including them with cash and cash equivalents when reconciling the total beginning and ending amounts for the periods shown on the statements of cash flows. This guidance is to be applied using a retrospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted. We adopted the new standard on January 1, 2018, and the prior period has been adjusted to conform to the current period presentation, which resulted in an increase in cash used in investing activities of $0.1 million for the 2017 Successor and Predecessor Periods, respectively, and $0.2 million for the year ended December 31, 2016.

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

	Successor		Predecessor	
	As of December 31,		As of	
	2018	2017	April 28, 2017	December 31, 2016
Cash and cash equivalents	$ 12,916	$ 12,711	$ 70,183	$ 80,565
Restricted cash included in other noncurrent assets	86	71	64	182
Total cash, cash equivalents and restricted cash as shown in the statements of cash flows	$ 13,002	$ 12,782	$ 70,247	$ 80,747

Restricted cash consists of funds for road maintenance and repairs.

In January 2017, the FASB issued U*pdate No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business*. This update clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This guidance is to be applied using a prospective method and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted. We adopted this new standard on January 1, 2018 and will apply it to any future acquisitions or disposals of assets or business.

In February 2017, the FASB issued *Update No. 2017-05, Other Income-Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets*. This update is meant to clarify existing guidance and to add guidance for partial sales of nonfinancial assets. This guidance is to be applied using a full retrospective method or a modified retrospective method as outlined in the guidance and is effective at the same time as Update 2014-09, *Revenue from Contracts with Customers (Topic 606)*. We adopted this new standard on January 1, 2018, and its adoption did not have a material impact on our financial statements and disclosures.

In May 2017, the FASB issued *Update No. 2017-09 Compensation – Stock Compensation (Topic 718)*. The purpose of this update is to provide clarity as to which modifications of awards require modification accounting under Topic 718. Previously issued guidance frequently resulted in varying interpretations and a diversity of practice. An entity should employ modification accounting unless the following are met: (1) the fair value of the award is the same immediately before and after the award is modified; (2) the vesting conditions are the same under both the modified award and the original award; and (3) the classification of the modified award is the same as the original award, either equity or liability. Regardless of whether modification accounting is utilized, award disclosure requirements under Topic 718 remain unchanged. This guidance was effective for annual or any interim periods beginning after December 15, 2017. We adopted this new standard on January 1, 2018. There was no material impact due to the adoption of this guidance.

In February 2016, the FASB issued *Update No. 2016-02 - Leases (Topic 842)* to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. Each lease that is recognized in the balance sheet will be classified as either finance or operating, with such classification affecting the presentation within the statements of cash flows. The standard will be effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted. The Company adopted this guidance on January 1, 2019, using the modified retrospective approach.

As part of the assessment process, the Company utilized external consultants to evaluate agreements under this guidance as well as assess the completeness of the lease population. The types of agreements evaluated under this guidance included the Company’s office leases, corporate asset rentals, drilling rig agreements, well-completion agreements, midstream infrastructure agreements, generator and compressor rentals, various other field equipment rentals, and other arrangements that included potential lease obligations under this guidance. The Company has completed the process of reviewing and determining the contracts and agreements to which the new guidance applies, and has implemented policies, internal controls, and processes that will be necessary to support the Company’s compliance with the additional accounting and disclosure requirements under this guidance. The lease administration system that will support the Company’s compliance with this guidance after adoption is operational and currently being populated with the necessary lease data and relevant assumptions.

Policy elections made by the Company as allowed under this guidance include (a) not recognizing leases with terms that are less than twelve months on the balance sheet, (b) combining lease and non-lease components as a single lease, (c) and applying practical expedients, which allow the Company to avoid reassessing contracts that commenced prior to adoption and were correctly classified under ASC 840. Adoption of this guidance will result in right-of-use assets and right-of-use liabilities on the balance sheets; however, the Company is not in a position to provide an estimate of the full quantitative impacts at this time.

In January 2018, the FASB issued *Update 2018-01, Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842*, which permits an entity to elect an optional transition practical expedient to not evaluate land easements existing or expiring before the entity's adoption of Update 2016-02 and not previously accounted for as leases. An entity that elects this practical expedient should evaluate new or modified land easements under this guidance beginning at the date Update 2016-02 is adopted. The Company plans to elect this practical expedient option at the same time it adopts Update 2016-02.

In July 2018, the FASB issued *Update No. 2018-11, Leases (Topic 842): Targeted Improvements*, which provides for an additional transition method that allows an entity to initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings (deficit) in the period of adoption. The Company plans to elect this transition method, which will eliminate the need for adjusting prior period comparable financial statements prepared under current lease accounting guidance. The Company will adopt this guidance at the same time it adopts Update 2016-02.

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. This update is effective for annual periods beginning after December 15, 2019, and interim periods within those annual periods. The standard will only impact the Company's disclosures.

In August 2018, the Securities and Exchange Commission, (“SEC”) issued a final rule, Disclosure Update and Simplification, that updates and simplifies SEC disclosure requirements. The primary changes include removing the requirement to disclose outside of the consolidated financial statements historical and pro forma ratios of earnings to fixed charges and historical low and high trading prices of the Company's common stock and adding a requirement to provide within the interim financial statements an analysis of changes in stockholders' equity for the current and comparative quarterly and year-to-date periods. Other changes included requirements related to segment, geographic area and dividend disclosures. The final rule was effective November 5, 2018. The Company adopted the standard for this annual report ending December 31, 2018, and it did not have a material impact on the Company's disclosures.

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, 2018, and through the filing date of this report.

NOTE 2 - REVENUE RECOGNITION

On January 1, 2018, the Company adopted ASC 606, using the modified retrospective approach for all applicable contracts at the date of initial adoption. Results for reporting periods beginning January 1, 2018 are presented in accordance with ASC 606, while prior period amounts are reported in accordance with ASC 605 - Revenue Recognition. The impact of adoption is as follows (in thousands):

	Year Ended December 31, 2018		
	As Unadjusted(1)	ASC 606 Adjustments	As Reported
Operating Revenues:			
Oil sales	$ 228,661	$ —	$ 228,661
Natural gas sales	18,076	4,293	22,369
NGLs sales	20,188	5,439	25,627
Oil and gas sales	$ 266,925	$ 9,732	$ 276,657
Operating expenses:			
Gathering, transportation and processing	$ —	$ 9,732	$ 9,732
Net income	$ 168,186	$ —	$ 168,186

(1) This column excludes the impact of ASC 606 and is consistent with the presentation prior to January 1, 2018.

Revenue from Contracts with Customers

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. Virtually all of our 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.

Performance Obligations

Oil Sales

Under our oil sales contracts we sell oil production at the wellhead, or other contractually agreed-upon delivery points, and collect an agreed-upon index price, net of pricing differentials. In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead, tank outlet, lease automatic custody transfer meter, or other contractually agreed-upon delivery point, at the net contracted price received.

Natural Gas and NGLs Sales

Under our natural gas processing contracts, we deliver 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 we maintain control through the outlet of the midstream processing facility, we recognize revenue on a gross basis, with gathering, transportation, and processing fees presented as an expense in our consolidated 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, we recognize revenue on a net basis.

Working Interest Partners

The Company and its working interest partners have entered into joint operating agreements, which govern the marketing and selling of the working interest partners' share of oil, natural gas, and NGLs. When selling oil, natural gas, and NGLs on behalf of working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis.

Transaction Price

As noted above, the transaction price is generally tied to a market index, net of adjustments or price differentials, with the variable consideration being the estimation process and related accruals; however, any identified differences between our revenue estimates and actual revenue received historically have not been significant.

As further described in *Note 8 - Commitments and Contingencies*, one contract with NGL Crude Logistics, LLP (“NGL”, known as the “NGL agreement”) 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 agreement based on approved production plans to determine if liquidated damages to NGL are probable. As of December 31, 2018, the Company believes that the volumes delivered to NGL will be in excess of the MVCs required then and during 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 agreement.

Transaction Price Allocated to Remaining Performance Obligations

Under our sales contracts, each unit of product represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and the transaction price for remaining performance obligations is determined in accordance with the preceding section during the period in which the performance obligation is satisfied. For our product sales that have a contract term of one year or less, we applied the practical expedient under the guidance, which states that a Company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Contract Balances

Under our product sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities under this guidance. At December 31, 2018 and December 31, 2017, our receivables from contracts with customers were $31.8 million and $28.5 million, respectively.

Prior-Period Performance Obligations

We record revenue in the month production is delivered to the purchaser. 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. We have existing internal controls for our revenue estimation process and related accruals, and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the period from January 1, 2018 through December 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

NOTE 3 - IMPAIRMENTS

During 2018, the Company incurred its standard annual amortization of $5.3 million on its emergence leases that were not held by production at the time of our emergence as disclosed in the abandonment and impairment of unproved properties line item in the accompanying statements of operations. There were no impairments for the year ended December 31, 2017.

During the first quarter of 2016, the Company impaired its oil and gas properties in the Mid-Continent region by $10.0 million, based upon the most recent bid for the assets received while the assets were held for sale. The Company also recorded unproved properties impairments of $24.7 million for non-core leases expiring within the Wattenberg Field. For additional discussion, please refer to *Note 12 - Fair Value Measurements.*

NOTE 4 - DIVESTITURES

During the first quarter of 2018, the Company established a plan to sell all of the Company's assets within its Mid-Continent region and North Park Basin in order to focus on and partially fund the development of our core assets in the Wattenberg Field in Colorado, at which point they were deemed held for sale.

The Company sold its North Park Basin assets on March 9, 2018 for minimal net proceeds and full release of all current and future obligations resulting in a minimal net loss. As of December 31, 2017, the assets within the Company's North Park Basin represented $5.4 million, net of accumulated depreciation, depletion, and amortization; and a corresponding asset retirement obligation liability of approximately $5.4 million.

On August 6, 2018, the Company entered into an agreement to simultaneously close and divest of all of its assets within its Mid-Continent region. Net proceeds from the sale amounted to $102.9 million, subject to customary post-closing adjustments, resulting in a gain of approximately $27.3 million, included in the gain on sale of properties line item in the accompanying statements of operations. The original purchase price of $117.0 million was subject to customary purchase-price adjustments, comprised of operational cash activity related to the Mid-Continent assets, for the time period between the effective date of February 1, 2018 and the closing date of August 6, 2018. The divestiture did not represent a strategic shift and is not expected to have a significant effect on the Company's operations or financial results; therefore, the disposal did not meet the criteria of discontinued operations.

NOTE 5 - OTHER NONCURRENT ASSETS

Other noncurrent assets contain the following (in thousands):

	Successor	
	As of December 31,	
	2018	2017
Operating bonds	$ 2,713	$ 2,683
Deferred financing costs	1,710	—
AMT credit refund(1)	376	376
Restricted cash	86	71
Other noncurrent assets	$ 4,885	$ 3,130

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

NOTE 6 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

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

	Successor	
	As of December 31,	
	2018	2017
Drilling and completion costs	$ 33,602	$ 21,833
Accounts payable trade	11,532	6,256
Accrued general and administrative cost	12,728	10,025
Lease operating expense	2,183	5,005
Accrued interest	241	250
Accrued oil and gas hedging	—	808
Production and ad valorem taxes and other	19,104	17,952
Total accounts payable and accrued expenses	$ 79,390	$ 62,129

NOTE 7 - LONG-TERM DEBT

Successor Debt

Current Credit Facility

On December 7, 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 “Current Credit Facility”). The Current Credit Facility has an aggregate original commitment amount of $750.0 million and matures on December 7, 2023. The initial borrowing base is $350.0 million, and there are no scheduled borrowing base redeterminations until May 1, 2019, with subsequent semi-annual redeterminations thereafter.

Borrowings under the Current Credit Facility will bear 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 Current 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 and (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 Current 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 Current Credit Facility is guaranteed by all wholly owned domestic 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.

The Current Credit Facility contains customary representations and affirmative covenants.

The Current 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, and (xix) sales or discounts of receivables (xx) dividend payments.

The Credit Parties are subject to certain financial covenants under the Current Credit Facility, including, without limitation, tested on the last day of each fiscal quarter, (i) a maximum ratio of the Company's consolidated indebtedness (subject to certain exclusions) to adjusted EBITDAX of 4.00 to 1.00 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.

The Company had $50.0 million outstanding on the Current Credit Facility as of December 31, 2018 and had no amounts outstanding under the credit facility in effect as of December 31, 2017.

In connection with the Current Credit Facility, the Company capitalized $2.2 million in deferred financing costs, of which, $1.7 million and $0.5 million of the total amounts capitalized are presented within other noncurrent assets and prepaid expenses and other line items, respectively, in the accompanying balance sheets as of December 31, 2018.

Prior Credit Facility

On the Effective Date, the Company entered into a new revolving credit facility, as the borrower, with KeyBank National Association, as the administrative agent, and certain lenders party thereto (the "Prior Credit Facility"). The new borrowing base of $191.7 million was redetermined semiannually, as early as April and October of each year. The original maturity date of this Prior Credit Facility was March 31, 2021.

The Prior Credit Facility restricted, among other items, certain dividend payments, additional indebtedness, purchase of margin stock, asset sales, loans, investments, and mergers. The Prior Credit Facility also contains certain financial covenants, which require the maintenance of certain financial and leverage ratios, as defined by the Prior Credit Facility. The Prior Credit Facility stated that beginning with the fiscal quarter ending September 30, 2017, and each following fiscal quarter through the maturity of the Prior Credit Facility, the Company's leverage ratio of indebtedness to EBITDAX was not to exceed 3.50 to 1.00. Beginning also with the fiscal quarter ending September 30, 2017, and each following fiscal quarter, the Company was required to maintain a minimum current ratio of 1.00 to 1.00 and a minimum interest coverage ratio of trailing twelve-month EBITDAX to trailing twelve-month interest expense of 2.50 to 1.00 as of the end of the respective fiscal quarter. The Prior Credit Facility also required the Company maintain a minimum asset coverage ratio of 1.35 to 1.00 as of the fiscal quarters ending September 30, 2017 and December 31, 2017. The minimum asset coverage ratio was only applicable until the first redetermination in April of 2018. As of December 31, 2017, and through the filing date of this report, the Company is in compliance with all of the Prior Credit Facility covenants.

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

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 dissolved and settled in full as of December 7, 2018.

Predecessor Debt

Predecessor Credit Facility

The predecessor credit facility, dated March 29, 2011, as amended, with a syndication of banks, provided for a total credit facility size of $1.0 billion. The predecessor 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 1.50% to 2.50% depending on the utilization level, and the base rate borrowings bore interest at the "Bank Prime Rate," as defined in the predecessor credit facility, plus 0.50% to 1.50%. The borrowing base on the predecessor credit facility was $150.0 million on October 31, 2016. As of December 31, 2016, the Company had $191.7 million outstanding under the credit facility and had a borrowing base deficiency of $41.7 million.

Predecessor Senior Unsecured Notes

The $500.0 million aggregate principal amount of 6.75% Senior Notes that, prior to the Company's Chapter 11 filing, matured on April 15, 2021 and the $300.0 million aggregate principal amount of 5.75% Senior Notes that matured on February 1, 2023 were unsecured senior obligations.

On the Effective Date, by operation of the Plan, all outstanding obligations under the Senior Notes were canceled and 9,481,610 shares of the Company's new common stock were issued. Please refer to *Note 15 - Chapter 11 Proceedings and Emergence* for additional discussion.

NOTE 8 - 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 material pending or overtly threatened legal actions against the Company of which it is aware.

Following negotiations with the Colorado Department of Public Health and Environment ("CDPHE"), over self-reported air quality noncompliance, on October 3, 2017, the Company agreed to a Compliance Order on Consent (the "COC") with the CDPHE. As part of the COC, the Company was required to pay a $0.2 million penalty. Additionally, as further required by the COC, the Company will perform certain mitigation projects and adopt certain procedures and processes addressing the monitoring, reporting, and control of air emissions with respect to the Company's storage tank facilities in the Wattenberg Field. The COC further set forth compliance requirements and criteria for continued operations and contains provisions regarding, record-keeping, modifications to the COC, circumstances under which the COC may terminate with respect to certain wells and facilities, and the sale or transfer of operational or ownership interests covered by the COC. In order to be in compliance, the Company incurred $1.2 million and $0.7 million in 2018 and 2017, respectively, and currently anticipates spending $3.1 million for 2019 through 2022. The COC can be terminated after four years with a showing of substantial compliance and CDPHE approval.

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 Company estimates that $2.3 million of the reimbursement is due to the Company's associated interest owners as shown in the accounts payable and accrued expenses line item in the accompanying balance sheets. The remaining net settlement amount of $5.1 million is presented as a reimbursement in the accompanying statements of operations within the severance and ad valorem taxes line item. This net settlement amount will be further reduced to reflect the reimbursement to the State of Colorado of a certain amount of severance tax credits received in connection with ad valorem taxes historically paid by the Company.

In February 2019, the Company was sent a notice of intent to sue ("NOI") letter by WildEarth Guardians ("WEG"), alleging failure to obtain required permits under the federal Clean Air Act before constructing and operating well production facilities in the ozone non-attainment area around the Denver Metropolitan and North Front Range of Colorado, among other things. The NOI letter appears to challenge long-established federal and state regulations and policies for permitting the construction and initial operation of upstream oil and gas production facilities in Colorado and elsewhere under the Clean Air Act and state counterpart statutes. Because the allegations made in the NOI letter are based on novel and unprecedented interpretations of complex federal and state air quality laws and regulations, it is not possible for the Company to determine at this time whether the allegations have merit or will lead to actual suit by WEG against the Company, but the Company will vigorously defend against such allegations if sued, and will coordinate as much as possible with state and federal permitting authorities to maintain the validity of its current and future air permits for such facilities.

Commitments

Upon emergence from bankruptcy, the new purchase agreement to deliver fixed determinable quantities of crude oil with NGL Crude Logistics, LLC became effective and the original purchase agreement with NGL was canceled. The terms of the new NGL agreement consists of defined volume commitments over an initial seven-year term. Under the terms of the new NGL agreement, the Company will be required to make periodic deficiency payments for any shortfalls in delivering minimum volume commitments, which are set in six-month periods beginning in January 2018. There were no minimum volume commitments for the year ending December 31, 2017. During 2018, the average minimum volume commitment was approximately 10,100 barrels per day and increases by approximately 41% from 2018 to 2019 and approximately 3% each year for the remainder of the contract, to a maximum of approximately 16,000 barrels per day. The aggregate financial commitment fee over the seven-year term, based on the minimum volume commitment schedule (as defined in the agreement) and the applicable differential fee, is $136.3 million as of December 31, 2018. Upon notifying NGL at least twelve months prior to the expiration date of the new NGL agreement, the Company may elect to extend the term of the new NGL agreement for up to three additional years.

The Company rejected its Denver office lease, which was confirmed in the Plan. On April 29, 2017, the Company entered into a new office lease agreement to rent office facilities. The lease is non-cancelable and expires in February 2022. Rent expense was $0.9 million for the year ended December 31, 2018, 2017 Successor Period, and 2017 Predecessor Period and $2.8 million for the year ended December 31, 2016.

The annual minimum commitment payments on the new NGL agreement and the new office lease for the next five years as of December 31, 2018 are presented below (in thousands):

		NGL Commitments (1)	Office Lease Commitments(2)	Total
2019	$	19,580	1,256	20,836
2020		27,949	1,351	29,300
2021		28,791	1,401	30,192
2022		29,485	234	29,719
2023		30,448	—	30,448
2024 and thereafter		—	—	—
Total	$	136,253	4,242	140,495

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(1) The above calculation is based on the minimum volume commitment schedule (as defined in the new NGL agreement) and applicable differential fees.
(2) The Company has subleased a portion of its office lease. The contractual amounts disclosed are presented gross, excluding total sublease income of $1.4 million.

NOTE 9 - STOCK-BASED COMPENSATION

2017 Long Term Incentive Plan

Upon emergence from bankruptcy, the Company adopted a new Long Term Incentive Plan (the “2017 LTIP”), as established by the pre-emergence Board, which allows for the issuance of restricted stock units, performance stock units, and stock options. On the Effective Date, the Company reserved 2,467,430 shares of the new common stock for issuance under its 2017 Long Term Incentive Plan. See below for further discussion of awards granted under the 2017 LTIP.

Inducement Awards

During the year ended December 31, 2018, the Company granted inducement awards in the form of RSUs separate and distinct from the 2017 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 2017 LTIP, established by the pre-emergence Board, allows for the issuance of RSUs to members of the Board of Directors and employees of the Company at the discretion of the Board of Directors. Each RSU represents one share of the Company's new 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.

During June 2017, the Company granted 63,894 RSUs to non-executive members of the Board of Directors, with a fair value of $2.3 million. This grant is intended to cover a three-year period, and the RSUs will vest in equal installments on each of the first three anniversaries. The vested shares will be released upon the earlier of the third anniversary of the grant date, a change of control, or the director's separation from the Company.

Total expense recorded for RSUs, inclusive of the Board of Director grants, for the Current and 2017 Successor Periods was $5.2 million and $7.9 million, respectively. The fair value of the RSUs granted from the 2017 LTIP during the Current and 2017 Successor Periods was $6.2 million and $13.4 million, respectively.

As of December 31, 2018, unrecognized compensation cost related to all RSUs was $10.2 million and will be amortized through 2023.

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

	Restricted Stock Units	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of 2017 Successor Period	—	$ —
Granted	452,996	$ 34.62
Vested	(173,200)	$ 34.19
Forfeited	(18,631)	$ 34.36
Non-vested as of December 31, 2017	261,165	$ 34.93
Granted	387,720	$ 27.80
Vested	(84,345)	$ 30.63
Forfeited	(83,705)	$ 29.78
Non-vested as of December 31, 2018	480,835	$ 30.83

Cash flows resulting from excess tax benefits are to be classified as part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for vested restricted stock in excess of the deferred tax asset attributable to stock compensation costs for such restricted stock. The Company recorded no excess tax benefits for the Current and 2017 Successor Periods.

Performance Stock Units

The 2017 LTIP, established by the pre-emergence Board, allows for the issuance of PSUs to employees at the sole discretion of the Board of Directors. The number of shares of the Company's common stock that may be issued to settle PSUs range 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 evenly split between two performance criterion. 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 average annual return on capital employed ("ROCE") for each year during the three-year performance period. Compensation expense associated with PSUs is recognized as general and administrative expense over the performance period.

The fair value of the PSUs was measured at the grant date with 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 PSUs, 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:

	For the Year Ended December 31, 2018
Expected term of award (in years)	3
Risk-free interest rate	2.76%
Expected daily volatility	2.6%

During the Current Successor Period, the Company recognized compensation expense for the PSUs of $0.6 million. The fair value of the PSUs granted during the Current Successor Period was $1.8 million. As of December 31, 2018, unrecognized compensation cost was $1.2 million and will be amortized through 2020.

A summary of the status and activity of performance stock units is presented below:

	Performance Stock Units	Weighted-Average Grant-Date Fair Value
Non-vested as of December 31, 2017	—	$ —
Granted[(1)]	59,641	$ 29.92
Forfeited	(5,952)	$ 29.92
Non-vested as of December 31, 2018	53,689	$ 29.92

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(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 times the number of units awarded, depending on the level of satisfaction of the performance condition.

Stock Options

The 2017 LTIP, established by the pre-emergence Board, allows for the issuance of stock options to the Company's employees at the sole discretion of the Board of Directors. Options expire ten years from the grant date unless otherwise determined by the Board of Directors. Compensation expense on the stock options are recognized as general and administrative expense over the vesting period of the award.

There were no stock options granted during the Current Successor Period. Total expense recorded for stock options for the Current and 2017 Successor Periods was $1.4 million and $3.7 million, respectively. The fair value of the stock options granted during the 2017 Successor Period was $6.8 million. As of December 31, 2018, unrecognized compensation cost was $0.8 million and will be amortized through 2020.

Stock options were valued using a Black-Scholes Model using the following assumptions:

	For the Year Ended December 31, 2017
Expected volatility	52.1%
Expected dividends	—%
Expected term (years)	6.0
Risk-free interest rate	1.96%

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. 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 is presented below:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at beginning of Current Successor Period	—	$ —	—	$ —
Granted	389,102	34.36	—	$ —
Exercised	—	—	—	$ —
Forfeited	(191,831)	34.36	9.3	$ —
Outstanding as of December 31, 2017	197,271	$ 34.36	9.3	$ —
Granted	—	—	—	$ —
Exercised	(32,037)	34.36	—	$ —
Forfeited	(32,425)	34.36	—	$ —
Outstanding as of December 31, 2018	132,809	$ 34.36	6.7	$ —
Options outstanding and exercisable as of December 31, 2018	61,880	$ 34.36	4.8	$ —

Predecessor Long Term Incentive Plan

The Company's Predecessor Long Term Incentive Plan (the "Predecessor Plan") had different forms of equity issuances allowed under it, including restricted stock, performance stock units, and long term incentive plan units ("predecessor awards"), as further described in this section. Upon emergence from bankruptcy, the Company's predecessor awards were canceled.

Restricted Stock under the Predecessor Long Term Incentive Plan

The Company granted shares of restricted stock to directors, eligible employees, and officers under its Predecessor Plan. Each share of restricted stock represented one share of the Company's common stock to be released from restriction upon completion of the vesting period. The awards typically vested in one-third increments over three years. Each share of restricted stock was entitled to a non-forfeitable dividend, if the Company were to declare one, and has the same voting rights as a share of the Company’s common stock. Shares of restricted stock were valued at the closing price of the Company’s common stock on the grant date and were recognized as general and administrative expense over the vesting period of the award.

The Company granted no shares of restricted stock under the Predecessor Plan during the 2017 or 2016 Predecessor Periods. The Company granted 568,832 shares of restricted stock under the Predecessor Plan to certain employees during 2015. The fair value of the restricted stock granted in 2015 was $13.8 million. The Company recognized compensation expense of $1.2 million and $6.1 million for the 2017 and 2016 Predecessor Periods, respectively.

There were no shares of restricted stock granted to non-employee directors under the Predecessor Plan during the 2017 Predecessor Period. During the year ended December 31, 2016, the Company issued 113,044 shares of restricted common stock under the Predecessor Plan to its non-employee directors. The Company recognized compensation expense of $0.04 million and $0.7 million for the 2017 and 2016 Predecessor Periods, respectively. These awards vested approximately one year after issuance.

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

	Predecessor			
	January 1, 2017 through April 28, 2017		For the Year Ended December 31, 2016	
	Restricted Stock	Weighted-Average Grant-Date Fair Value	Restricted Stock	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	368,887	$ 19.45	731,818	$ 29.47
Granted	—	$ —	113,044	$ 0.98
Vested	(111,996)	$ 32.22	(355,498)	$ 31.68
Forfeited	(5,134)	$ 29.55	(120,477)	$ 27.34
Canceled	(251,757)	$ 13.08	—	$ —
Non-vested at end of period	—	$ —	368,887	$ 19.45

The Company recorded no excess tax benefits for the 2017 and 2016 Predecessor Periods.

Performance Stock Units under the Predecessor Long Term Incentive Plan

The Company granted PSUs to certain officers under its Predecessor Plan. The number of shares of the Company’s common stock that may be issued to settle PSUs ranged from zero to two times the number of PSUs awarded. PSUs were determined at the end of each annual measurement period over the course of the three-year performance cycle in an amount up to two-thirds of the target number of PSUs that are eligible for vesting (such that an amount equal to 200% of the target number of PSUs may be earned during the performance cycle), although no stock was actually awarded to the participant until the end of the entire three-year performance cycle. Any PSUs that have not vested at the end of the applicable measurement period are forfeited. The performance criteria for the PSUs is based on a comparison of the Company’s TSR for the measurement period compared with the TSRs of a group of peer companies for the same measurement period. Compensation expense associated with PSUs was recognized as general and administrative expense over the measurement period. The TSR for the Company and each of the peer companies was determined by dividing (A)(i) the average share price for the last 30 trading days of the applicable measuring period, minus (ii) the average share price for the 30 trading days immediately preceding the beginning of the applicable measuring period, by (B) the average share price for the 30 trading days immediately preceding the beginning of the applicable measuring period. The number of earned shares of the Company's common stock was calculated based on which quartile its TSR percentage ranks as of the end of the annual measurement period relative to the other companies in the comparator group.

The fair value of the PSUs was measured at the grant date with a stochastic process method using a Monte Carlo 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 PSUs, 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 Monte Carlo Model, was deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company’s expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period, as well as the volatilities for each of the Company’s peers.

The Company granted no PSUs under the Predecessor Plan during the 2017 and 2016 Predecessor Periods. The Company recognized compensation expense for the Predecessor Company of $0.5 million and $1.8 million for the 2017 and 2016 Predecessor Periods, respectively, relating to the 2015 PSUs.

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

	Predecessor			
	January 1, 2017 through April 28, 2017		For the Year Ended December 31, 2016	
	PSU	Weighted-Average Grant-Date Fair Value	PSU	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year[(1)]	21,538	$ 33.31	114,833	$ 35.27
Granted[(1)]	—	$ —	—	$ —
Vested[(1)]	—	$ —	(59,725)	$ 36.61
Forfeited[(1)]	—	$ —	(33,570)	$ 35.55
Canceled[(1)]	(21,538)	$ 33.31	—	$ —
Non-vested at end of period[(1)]	—	$ —	21,538	$ 33.31

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(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 times the number of PSUs awarded, depending on the level of satisfaction of the performance condition.

During the 2017 Predecessor Period the third tranche of the 2015 awards had a zero-times multiplier, in accordance with the terms of the respective PSU awards. During the year ended December 31, 2016, the third tranche of the 2014 awards and the second tranche of the 2015 awards had a zero-times multiplier, in accordance with the terms of the respective PSU awards.

Predecessor Long Term Incentive Plan Units

The Company granted no Predecessor LTIP units (“units”) during the 2017 Predecessor Period. During the year end December 31, 2016, the Company granted 2,958,558 units for a total fair value $2.9 million, that settled in shares of the Company's common stock upon vesting. The units would vest in one-third increments over three years. The units contained a share price cap of $26 that incrementally decreases the number of shares of the Company's common stock that will be released upon vesting if the Company's common stock were to exceed the share price cap.

Total expense recorded for the units for the Predecessor Company for the 2017 and 2016 Predecessor Periods was $0.4 million and $0.9 million, respectively.

A summary of the status and activity of non-vested units for the 2017 and 2016 Predecessor Periods is presented below.

	Predecessor			
	January 1, 2017 through April 28, 2017		For the Year Ended December 31, 2016	
	LTIP Units	Weighted-Average Grant-Date Fair Value	LTIP Units	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	2,443,402	$ 0.99	—	$ —
Granted	—	$ —	2,958,558	$ 0.99
Vested	(767,848)	$ 0.98	—	$ —
Forfeited	(126,616)	$ 0.98	(515,156)	$ 0.98
Canceled	(1,548,938)	$ 0.99	—	$ —
Non-vested at end of period	—	$ —	2,443,402	$ 0.99

401(k) Plan

The Company has a defined contribution retirement plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to the contribution limits established under the IRC. The Company matches each employee's contribution up to six percent of the employee's base salary. The Company's matching contributions to the 401(k) Plan were $1.1 million, $0.6 million, $0.6 million, and $2.0 million for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and the year ended December 31, 2016, respectively.

NOTE 10 - INCOME TAXES

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax 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):

	Successor		Predecessor	
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Current tax benefit				
Federal	$ —	$ 376	$ —	$ —
State	—	—	—	—
Deferred tax benefit	—	—	—	—
Total income tax benefit	$ —	$ 376	$ —	$ —

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

	Successor	
	As of December 31,	
	2018	2017
Deferred tax liabilities:		
Oil and gas properties	$ 52,006	$ —
Derivative liability	8,527	—
Total deferred tax liabilities	60,533	—
Deferred tax assets:		
Federal and state tax net operating loss carryforward	137,567	117,115
Oil and gas properties	—	1,319
Derivative liability	—	3,457
Reclamation costs	7,251	9,516
Stock compensation	1,635	1,419
Accrued compensation	1,308	1,285
Inventory	1,577	1,529
Settlement liabilities	—	—
AMT credit	—	—
State bonus depreciation addback	—	1,089
Other long-term assets	271	231
Total deferred tax assets	149,609	136,960
Less: Valuation allowance	89,076	136,960
Total deferred tax assets after valuation allowance	—	—
Total non-current net deferred tax liability	$ —	$ —

The Company has $577.6 million and $470.3 million of net operating loss carryovers for federal income tax purposes as of December 31, 2018 and 2017, respectively. Federal net operating loss carryforwards incurred prior to January 1, 2018 of $470.3 million will begin to expire in 2036. Federal net operating loss carryforwards incurred after December 31, 2017 of $107.3 million have no expiration and can only be used to offset 80% of taxable income when utilized.

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, rate changes, and other permanent differences, as follows (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Federal statutory tax (expense) benefit by applying the statutory rate	$ 35,319	$ 1,889	$ (931)	$ 69,633
Decrease (increase) in tax resulting from:				
State tax expense net of federal benefit	6,556	172	(85)	6,358
Prior year true-up	(458)	—	(7,572)	—
Stock compensation	854	—	(1,773)	—
Permanent differences	61	(715)	(35,273)	—
Rate change	(421)	(73,956)	—	—
NOL Adjustment	5,973	—	—	—
Other	—	(642)	—	(317)
Valuation allowance	(47,884)	73,628	45,634	(75,674)
Total income tax benefit	$ —	$ 376	$ —	$ —

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 benefit 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.

During the year ended December 31, 2017, the decrease in tax rate was primarily due to the enactment of the Tax Cuts and Jobs Act ("Tax Act"). There was $0.4 million of current income tax benefits in the accompanying statements of operations due to the AMT payments being refunded as prescribed in the Tax Act. The valuation allowance decreased to $137.0 million in 2017 due to decreased tax rate as mandated by the Tax Act.

During the year ended December 31, 2016, the decrease in tax rate was primarily due to placing a valuation allowance against net deferred tax assets. There was no deferred income tax benefit or expense in the accompanying statements of operations. The valuation allowance increased to $256.2 million in 2016 due to continued deterioration of our operational results.

The Company had no unrecognized tax benefits as of December 31, 2018, 2017, and 2016.

NOTE 11 - ASSET RETIREMENT OBLIGATIONS

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

The Company's estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimated costs to abandon the wells, and regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred and ranges from 8% to 18% for the Predecessor Company and ranges from 5% to 7% for the Successor Company.

Upon the Company's emergence from bankruptcy, as discussed in *Note 15 - Chapter 11 Proceedings and Emergence* and *Note 16 - Fresh-Start Accounting*, the Company applied fresh-start accounting. This included adjusting the asset retirement obligations based on the estimated fair values at April 28, 2017. A roll-forward of the Company's asset retirement obligation is as follows (in thousands):

Balance as of January 1, 2017 (Predecessor)	$	30,833
Liabilities settled		(218)
Accretion expense		1,045
Ending balance as of April 28, 2017 (Predecessor)	$	31,660
Fair value fresh-start adjustment	$	(2,599)
Beginning balance as of April 29, 2017 (Successor)	$	29,061
Additional liabilities incurred		130
Accretion expense		1,370
Liabilities settled		(780)
Revisions to estimate		8,481
Ending balance as of December 31, 2017 (Successor)	$	38,262
Additional liabilities incurred		373
Accretion expense		1,831
Liabilities settled		(1,627)
Revisions to estimate		1,490
Sold properties		(10,924)
Ending balance as of December 31, 2018 (Successor)		29,405

Revisions to the liability could occur due to changes in the estimated economic lives, abandonment costs of the wells, inflation rates, credit-adjusted risk-free rates, along with newly enacted regulatory requirements. Revisions to estimates for the year ended December 31, 2018 were primarily a result of an increase in the credit-adjusted risk-free rate applied at year-end and an increase in the inflation rate on wells that had an asset retirement obligation as of the beginning of the year, offset by a slight decrease in abandonment costs. Revisions to estimates for the 2017 Successor Period were a result of a decrease in the credit-adjusted risk-free rate applied at year-end, decreased estimated economic well lives, and an increase in abandonment costs.

NOTE 12 - FAIR VALUE MEASUREMENTS

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

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

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

Level 3: Significant inputs to the valuation model are unobservable

Financial 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.

The following tables present the Company's financial and non-financial assets and liabilities that were accounted for at fair value as of December 31, 2018 and 2017 and their classification within the fair value hierarchy:

	Successor		
	As of December 31, 2018		
	Level 1	Level 2	Level 3
	(in thousands)		
Derivative assets[1]	$ —	$ 38,272	$ —
Derivative liabilities[1]	$ —	$ 183	$ —
Asset retirement obligations[2]	$ —	$ —	$ 1,490

	Successor		
	As of December 31, 2017		
	Level 1	Level 2	Level 3
	(in thousands)		
Derivative assets[1]	$ —	$ 494	$ —
Derivative liabilities[1]	$ —	$ 14,395	$ —
Asset retirement obligations[2]	$ —	$ —	$ 8,481

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(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.

(2) This represents the revision to estimates of the asset retirement obligation, which is a non-financial liability that is measured at fair value on a nonrecurring basis. Please refer to the *Asset Retirement Obligation* section below for additional discussion.

Derivatives

Fair value of all derivative instruments are estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. All valuations were compared against counterparty statements to verify the reasonableness of the estimate. The Company's commodity swaps and collars 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.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs exceed the sum of the undiscounted cash flows. 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 oil and gas property impairments during the years ended December 31, 2018 and 2017. For the year ended December 31, 2016, the Company impaired its oil and gas properties in the Mid-Continent region by $10.0 million, reflecting the difference between their $110.0 million carrying value and their $100.0 million fair value. For additional discussion on impairments, please refer to *Note 3 - Impairments*.

Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be fully recoverable. To measure the fair value of unproved properties, the Company uses Level 3 inputs and the income valuation technique, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, remaining lease life, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If a relevant estimated selling price is not available, the Company uses the price received for similar acreage in recent transactions by the Company or other market participants in the principal market. During 2018, the Company incurred its standard annual amortization of $5.3 million on its emergence leases that were not held by production as disclosed in the abandonment and impairment of unproved properties line item in the accompanying statements of operations. There were no unproved oil and gas property impairments during the year ended December 31, 2017. During the year ended December 31, 2016, the Company impaired non-core acreage in the Wattenberg Field due to lease expirations, which had a carrying value of $187.4 million, to its fair value of $162.7 million, and recognized an impairment of unproved properties of $24.7 million.

Asset Retirement Obligation

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Upon completion of wells and natural gas plants, the Company records an asset retirement obligation at fair value using Level 3 assumptions. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. The Company had $1.5 million and $8.5 million of asset retirement obligations recorded at fair value as of December 31, 2018 and 2017, respectively.

Long-term Debt

Upon emergence from bankruptcy, the Company's Senior Notes were canceled and the predecessor credit facility was paid in full. The Company's credit facility approximates fair value as the applicable interest rates are floating. The Company had $50.0 million outstanding under the credit facility as of December 31, 2018. There were no long-term debt amounts outstanding as of December 31, 2017.

NOTE 13 - DERIVATIVES

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

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

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. 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.

A put option provides the Company the right, but not the obligation, to sell a specified underlying security at a designated price within a specified time frame.

As of December 31, 2018, 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
1Q19								
Cashless Collar	4,000	$50.88/$63.83	7,600	$2.75/$3.22	—	—	—	—
Swap	4,000	$59.16	1,500	$3.13	7,600	$0.67	10,000	$2.17
Put	500	$55.00	—	—	—	—	—	—
2Q19								
Cashless Collar	5,330	$54.42/$67.57	2,505	$2.75/$3.22	—	—	—	—
Swap	3,500	$57.84	—	—	—	—	16,703	$2.11
Put	500	$55.00	—	—	—	—	—	—
3Q19								
Cashless Collar	3,000	$59.17/$75.72	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	20,000	$2.10
Put	500	$55.00	—	—	—	—	—	—
4Q19								
Cashless Collar	3,000	$59.17/$75.72	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	20,000	$2.10
Put	500	$55.00	—	—	—	—	—	—
1Q20								
Swap	3,000	$63.48	—	—	—	—	—	—

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
1Q19								
Cashless Collar	4,656	$51.46/$65.40	7,600	$2.75/$3.22	—	—	—	—
Swap	4,000	$59.16	1,500	$3.13	7,600	$0.67	11,639	$2.20
Put	172	$55.00	—	—	—	—	—	—
2Q19								
Cashless Collar	6,330	$54.51/$68.74	2,505	$2.75/$3.22	—	—	—	—
Swap	3,500	$57.84	—	—	—	—	19,203	$2.15
Put	—	—	—	—	—	—	—	—
3Q19								
Cashless Collar	4,000	$58.13/$75.54	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	22,500	$2.13
Put	—	—	—	—	—	—	—	—
4Q19								
Cashless Collar	4,000	$58.13/$75.54	—	—	—	—	—	—
Swap	5,000	$59.92	—	—	—	—	22,500	$2.13
Put	—	—	—	—	—	—	—	—
1Q20								
Swap	3,000	$63.48	—	—	—	—	2,500	$2.40
Collar	2,000	$55.00/$62.00	—	—	—	—	—	—

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, 2018 and 2017 (in thousands):

		Successor	
		As of December 31,	
		2018	2017
	Balance Sheet Location	Fair Value	Fair Value
Derivative Assets:			
Commodity contracts	Current assets	$ 34,408	$ 488
Commodity contracts	Noncurrent assets	3,864	6
Derivative Liabilities:			
Commodity contracts	Current liabilities	(183)	(11,423)
Commodity contracts	Long-term liabilities	—	(2,972)
Total derivative assets (liabilities), net		$ 38,089	$ (13,901)

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

	Successor		Predecessor	
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Derivative cash settlement gain (loss):				
Oil contracts	$ (17,700)	$ (1,486)	$ —	$ 18,333
Gas contracts	(460)	22	—	—
Total derivative cash settlement gain (loss)(1)	$ (18,160)	$ (1,464)	$ —	$ 18,333
Change in fair value gain (loss)	48,431	(13,901)	$ —	$ (29,567)
Total derivative gain (loss)(1)	$ 30,271	$ (15,365)	$ —	$ (11,234)

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(1) Total derivative gain (loss) and the derivative cash settlement gain (loss) for each of the periods presented above is reported in the derivative (gain) loss and derivative cash settlements line items on the accompanying statements of cash flows within the net cash provided by operating activities.

NOTE 14 - 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 range 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 is based on the number of shares, if any, that would be exercised at the end of the respective reporting period, assuming that date was the end of such stock options' term. The number of potentially dilutive shares related to the warrants is based on the number of shares, if any, that would be exercisable at the end of the respective reporting period.

Please refer to *Note* 9 - *Stock-Based Compensation* for additional discussion.

The RSUs, PSUs, stock options, and warrants of the Company are all non-participating securities, and therefore, the Company uses the treasury stock method to calculate earnings per share as shown in the following table (in thousands, except per share amounts):

	Successor	
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017
Net income (loss)	$ 168,186	$ (5,020)
Basic net income (loss) per common share	$ 8.20	$ (0.25)
Diluted net income (loss) per common share	$ 8.16	$ (0.25)
Weighted-average shares outstanding - basic	20,507	20,427
Add: dilutive effect of contingent stock awards	96	—
Weighted-average shares outstanding - diluted	20,603	20,427

There were 170,755 shares which were anti-dilutive for the year ended December 31, 2018. The Company's warrants exercise price were in excess of the Company's stock price, therefore, they were excluded from the earnings per share calculation.

The Company was in a net loss position for the 2017 Successor Period, which made the 375,123 potentially dilutive shares anti-dilutive.

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

The Predecessor Company issued units, which represented the right to receive, upon vesting, shares of the Predecessor Company's common stock on a one-to-one basis up to a share price of $26. In the event the price of the Company's common stock were to exceed $26, the number of shares distributed would be adjusted downward so that the shares distributed would represent a value equivalent to $26 per share.

The Predecessor Company issued PSUs, which represented the right to receive, upon settlement of the PSUs, a number of shares of the Predecessor Company's common stock that range 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 measurement period applicable to such PSUs. Please refer to *Note* 9 - *Stock-Based Compensation* for additional discussion.

The following table sets forth the calculation of income (loss) per basic and diluted shares from net income (loss) for the Predecessor Periods ended April 28, 2017 and December 31, 2016:

	Predecessor	
	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
	(in thousands, except per share amounts)	
Net income (loss)	$ 2,660	$ (198,950)
Less: undistributed income to unvested restricted stock	120	—
Undistributed income (loss) to common shareholders	2,540	(198,950)
Basic net income (loss) per common share	$ 0.05	$ (4.04)
Diluted net income (loss) per common share	$ 0.05	$ (4.04)
Weighted-average shares outstanding - basic	49,559	49,268
Add: dilutive effect of contingent PSUs	1,412	—
Weighted-average shares outstanding - diluted	50,971	49,268

The 2017 Predecessor Period had 258,126 anti-dilutive shares. The Company was in a net loss position for the 2016 Predecessor Period, which made the 519,362 potentially dilutive shares, anti-dilutive. The participating shareholders are not contractually obligated to share in losses, and therefore, the entire net loss is allocated to the outstanding common shareholders.

NOTE 15 - CHAPTER 11 PROCEEDINGS AND EMERGENCE

On December 23, 2016, Bonanza Creek Energy, Inc. and its subsidiaries entered into a Restructuring Support Agreement with (i) holders of approximately 51% in aggregate principal amount of the Company's 5.75% Senior Notes due 2023 (“5.75% Senior Notes”) and 6.75% Senior Notes due 2021 (“6.75% Senior Notes”), collectively (the “Senior Notes”) and (ii) NGL Energy Partners, LP and NGL Crude Logistics, LLC (collectively “NGL”).

On January 4, 2017, the Company filed voluntary petitions under Chapter 11 of the United States Bankruptcy Code. The Debtors received bankruptcy court confirmation of their Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017.

During the bankruptcy proceedings, the Company conducted normal business activities and was authorized to pay and did pay pre-petition liabilities.

In addition, subject to specific exceptions under the Bankruptcy Code, the Chapter 11 filings automatically stayed most judicial or administrative actions against the Company and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. As a result, we did not record interest expense on the Company’s Senior Notes from January 6, 2017, the agreed-upon date, through April 28, 2017. For that period, contractual interest on the Senior Notes totaled $16.0 million.

Reorganization

On the Effective Date, the Senior Notes and existing common shares of the Company (“existing common shares”) were canceled, and the reorganized Company issued: (i) new common stock; (ii) three year warrants (“warrants”); and (iii) rights (the “subscription rights”) to acquire the new common shares offered in connection with the rights offering (the “rights offering”).

- the Senior Notes aggregate principal amount of $800.0 million, plus $14.9 million of accrued and unpaid pre-petition interest and $51.2 million of prepayment premiums was settled for 46.6% or 9,481,610 shares of the Company's new common stock;
- the Company issued 803,083 or 3.9% of the new common stock to holders of our existing common stock, of which 1.75% was for the ad hoc equity committee settlement in exchange for $7.5 million, on terms equivalent to the rights offering;

- the Company issued 10,071,378 shares of new common stock in exchange for $200.0 million relating to the rights offering;
- the Company issued 1,650,510 of warrants entitling their holders upon exercise thereof, on a pro rata basis, to 7.5% of the total outstanding new common shares at a per share price of $71.23 per warrant; and
- the Company reserved 2,467,430 shares of the new common stock for issuance under its 2017 Long Term Incentive Plan ("LTIP").

Pursuant to the terms of the approved Plan the following transactions were completed on the Effective Date;

- the Company paid Silo Energy, LLC ("Silo") the contract settlement amount of $7.2 million in full;
- with respect to the predecessor credit facility, dated March 29, 2011 (the "predecessor credit facility"), principal, accrued interest, and fees of $193.7 million were paid in full;
- the Company paid $1.6 million for the 2016 Short Term Incentive Plan ("2016 STIP") to various employees;
- the Company funded an escrow account in the amount of $17.2 million for professional service fees attributable to its advisers;
- the Company paid $13.8 million for professional services attributable to advisers of third parties involved in the bankruptcy proceedings;
- the Company emerged with cash on hand of $70.2 million for operations; and
- the Company amended its articles of incorporation and bylaws for the authorization of the new common stock.

As confirmed in the Plan, the Company terminated its purchase agreement with Silo on February 1, 2017, and entered into a settlement agreement that allowed Silo to: (i) retain the $5.0 million adequate assurance deposit maintained, (ii) retain the Company's $8.7 million crude oil revenue receivable due to the Company for December 2016 production, and (iii) receive additional cash payment of $7.2 million, which was paid on the Effective Date. The $21.0 million settlement is shown in the contract settlement expense line item in the accompanying statements of operations as of December 31, 2016.

Board of Directors

Upon emergence from bankruptcy the Company's Board of Directors was made up of seven individuals, two of which were existing board members, Richard J. Carty and Jeffrey E. Wojahn, and five new board members consisting of Paul Keglevic, Brian Steck, Thomas B. Tyree, Jr., Jack E. Vaughn, and Scott D. Vogel were appointed.

Executive Departure

On June 11, 2017, Richard J. Carty resigned as a member of the Board of Directors and left his role as President and Chief Executive Officer of the Company. In connection with the departure of Mr. Carty, the Board of Directors appointed R. Seth Bullock, a managing director of Alvarez & Marsal, LLC, interim Chief Executive Officer.

Effective April 11, 2018, the Company appointed Eric T. Greager as the new President and Chief Executive Officer of the Company. Mr. Greager also joined the Company's Board of Directors.

NOTE 16 - FRESH-START ACCOUNTING

Upon the Company's emergence from Chapter 11 bankruptcy, the Company adopted fresh-start accounting, pursuant to FASB ASC *852, Reorganizations*, and applied the provisions thereof to its financial statements. The Company qualified for fresh-start accounting because: (i) the holders of existing voting shares of the Predecessor Company received less than 50% of the voting shares of the Successor Company; and (ii) the reorganization value of the Company's assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims. The Company applied fresh-start accounting as of April 28, 2017, when it emerged from bankruptcy protection. Adopting fresh-start accounting results in a new reporting entity for financial reporting purposes with no beginning retained earnings or deficit as of the fresh-start reporting date. The cancellation of all existing shares outstanding on the Effective Date and issuance of new shares of the Successor Company caused a related change of control of the Company under ASC 852.

Reorganization Value

Under fresh-start accounting, reorganization value represents the fair value of the Successor Company's total assets and is intended to approximate the amount a willing buyer would pay for the assets immediately after restructuring. Under application of fresh-start accounting, the Company allocated the reorganization value to its individual assets based on their estimated fair values.

The Company's reorganization value is derived from an estimate of enterprise value. Enterprise value represents the estimated fair value of an entity's long-term debt, other interest bearing liabilities, and shareholders' equity, less total cash and cash equivalents. In support of the Plan, the enterprise value of the Successor Company was estimated and approved by the Bankruptcy Court to be in the range of $570.0 million to $680.0 million. Based on the estimates and assumptions used in determining the enterprise value, as further discussed below, the Company estimated the enterprise value to be approximately $643.0 million. This valuation analysis was prepared with the assistance of an independent third-party consultant utilizing reserve information prepared by the Company's internal reserve engineers, internal development plans and schedules, other internal financial information and projections and the application of standard valuation techniques including risked net asset value analysis and comparable public company metrics.

The Company's principal assets are its oil and gas properties. The Company determined the fair value of its oil and gas properties based on the discounted cash flows expected to be generated from these assets segregated into geographic regions. The computations were based on market conditions and reserves in place as of the Effective Date. Discounted cash flow models were generated using the estimated future revenues and development and operating costs for all developed wells and undeveloped locations comprising our proved reserves. The proved locations were limited to wells expected to be drilled in the Company's five year plan. Future cash flows before application of risk factors were estimated by using the New York Mercantile Exchange five year forward prices for West Texas Intermediate oil and Henry Hub natural gas with inflation adjustments applied to periods beyond five years. The prices were further adjusted for typical differentials realized by the Company for the location and product quality. Wattenberg Field oil differential estimates were based on the new NGL purchase agreement that was confirmed as part of the Plan. Development costs were based on recent bids received by the Company and the operating costs were based on actual costs, and both were adjusted by the same inflation rate used for revenues. The discounted cash flow models also included estimates not typically included in proved reserves, such as an industry standard general and administrative expense and income tax expense. Due to the limited drilling plans that we had in place, proved undeveloped locations were risked within industry standards.

The risk-adjusted after-tax cash flows were discounted at a rate of 11.0%. This rate was determined from a weighted-average cost of capital computation, which utilized a blended expected cost of debt and expected returns on equity for similar industry participants.

From this analysis the Company concluded the fair value of its proved, probable, and possible reserves was $397.3 million, $146.8 million, and $31.7 million, respectively, as of the Effective Date. The Company also reviewed its undeveloped leasehold acreage and determined that the fair value of its probable and possible reserves appropriately capture the fair value of its undeveloped leasehold acreage.

The Company performed an analysis of its Rocky Mountain Infrastructure, LLC ("RMI") assets using a replacement cost method which estimated the assets' replacement cost (for new assets), less any depreciation, physical deterioration, or obsolescence, resulting in a fair value of $103.1 million.

The Company follows the lower of cost or net realizable value when valuing inventory of oilfield equipment. The valuation of the inventory of oilfield equipment as of the Effective Date did not yield a material difference from the Company's carrying value immediately prior to emergence from bankruptcy; as such, there was no valuation adjustment recorded.

The valuation of the Company's other property and equipment as of the Effective Date did not yield a material difference from the Predecessor Company's net book value; as such there was no valuation adjustment recorded.

Our liabilities on the Effective Date include working capital liabilities and asset retirement obligations. Our working capital liabilities are ordinary course obligations, and their carrying amounts approximate their fair values. The asset retirement obligation was reset using a revised credit-adjusted risk-free rate and known attributes as of the Effective Date, resulting in a $29.1 million obligation.

In conjunction with the Company's emergence from bankruptcy, the Company issued 1,650,510 warrants to existing equity holders. The fair value of $4.1 million was estimated using a Black-Scholes pricing model. The model used the following assumptions; an expected volatility of 40%, a risk-free interest rate of 1.44%, a stock price of $34.36, a strike price of $71.23, and an expiration date of 3 years.

The following table reconciles the enterprise value to the estimated fair value of Successor Company's common stock as of the Effective Date (in thousands, except per share amounts):

Enterprise Value	$	642,999
Plus: Cash and cash equivalents		70,183
Less: Interest bearing liabilities		(29,061)
Less: Fair value of warrants		(4,081)
Fair value of Successor common stock	$	680,040
Shares outstanding at April 28, 2017		20,356
Per share value	$	33.41

The following table reconciles the enterprise value to the estimated reorganization value as of the Effective Date (in thousands):

Enterprise Value	$	642,999
Plus: Cash and cash equivalents		70,183
Plus: Working capital liabilities		63,871
Plus: Other long-term liabilities		17,919
Reorganization value of Successor assets	$	794,972

Successor Condensed Consolidated Balance Sheet

The adjustments set forth in the following condensed consolidated balance sheet reflect the effect of the consummation of the transactions contemplated by the Plan (reflected in the column “Reorganization Adjustments”) as well as estimated fair value adjustments as a result of the adoption of fresh-start accounting (reflected in the column “Fresh-Start Adjustments”). The explanatory notes highlight methods used to determine estimated fair values or other amounts of assets and liabilities, as well as significant assumptions.

	Predecessor Company	Reorganization Adjustments		Fresh-Start Adjustments		Successor Company
	(in thousands, except share amounts)					
ASSETS						
Current Assets:						
Cash and cash equivalents	$ 96,286	$ (26,103)	(1)	$ —		$ 70,183
Accounts receivable:						
Oil and gas sales	24,876	—		—		24,876
Joint interest and other	3,028	—		—		3,028
Prepaid expenses and other	4,952	—		—		4,952
Inventory of oilfield equipment	4,218	—		—		4,218
Total current assets	133,360	(26,103)		—		107,257
Property and equipment (successful efforts method):						
Proved properties	2,531,834	—		(2,031,373)	(6)	500,461
Less: accumulated depreciation, depletion and amortization	(1,720,736)	—		1,720,736	(6)	—
Total proved properties, net	811,098	—		(310,637)		500,461
Unproved properties	163,781	—		14,679	(6)	178,460
Wells in progress	18,002	—		(18,002)	(7)	—
Other property and equipment, net	6,056	—		—		6,056
Total property and equipment, net	998,937	—		(313,960)		684,977

Other noncurrent assets	2,738	—	—	2,738
Total assets	$ 1,135,035	$ (26,103)	$ (313,960)	$ 794,972
LIABILITIES AND STOCKHOLDERS'S EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 72,635	$ (33,701) (2)	$ —	$ 38,934
Oil and gas revenue distribution payable	24,937	—	—	24,937
Predecessor credit facility - current portion	191,667	(191,667) (3)	—	—
Total current liabilities	289,239	(225,368)	—	63,871
Long-term liabilities:				
Ad valorem taxes	17,919	—	—	17,919
Asset retirement obligations for oil and gas properties	31,660	—	(2,599) (8)	29,061
Liabilities subject to compromise	873,292	(873,292) (4)	—	—
Total liabilities	$ 1,212,110	$ (1,098,660)	$ (2,599)	$ 110,851
Stockholders' equity:				
Predecessor preferred stock	—	—	—	—
Predecessor common stock	49	—	(49) (9)	—
Additional paid in capital	816,679	—	(816,679) (9)	—
Successor common stock	—	204 (5)	—	204
Successor warrants	—	4,081 (5)	—	4,081
Additional paid-in capital	—	679,836 (5)	—	679,836
Retained deficit	(893,803)	388,436 (4)	505,367 (10)	—
Total stockholders' equity	(77,075)	1,072,557	(311,361)	684,121
Total liabilities and stockholders' equity	$ 1,135,035	$ (26,103)	$ (313,960)	$ 794,972

Reorganization Adjustments

(1) The following table reflects the net cash payments made upon emergence on the Effective Date (in thousands):

Sources:	
Proceeds from rights offering	$ 200,000
Proceeds from ad hoc equity committee	7,500
Total sources	$ 207,500
Uses and transfers:	
Payment on predecessor credit facility (principal, interest and fees)	$ (193,729)
Payment and funding of escrow account related to professional fees	(17,193)
Payment of professional fees and other	(13,831)
Payment of Silo contract settlement and other	(7,228)
Payment of remaining 2016 STIP	(1,622)
Total uses and transfers	$ (233,603)
Total net sources, uses and transfers	$ (26,103)

(2) The following table shows the decrease of accounts payable and accrued liabilities attributable to reorganization items settled or paid upon emergence (in thousands):

Accounts payable and accrued expenses:		
Accrued 2016 STIP payment	$	(1,574)
Escrow account funding		(17,193)
Professional fees and other		(13,831)
Accrued unpaid interest on predecessor credit facility		(1,103)
Total accounts payable and accrued expenses settled	$	(33,701)

(3) Represents the payment in full of the predecessor credit facility on the Effective Date.

(4) On the Effective Date, the obligations of the Company with respect to the Senior Notes were canceled. Liabilities subject to compromise were settled as follows in accordance with the Plan (in thousands):

Senior Notes	$	800,000
Accrued interest on Senior Notes (pre-petition)		14,879
Make-whole payment on Senior Notes		51,185
Silo contract settlement accrual		7,228
Total liabilities subject to compromise of the predecessor		873,292
Rights offering		200,000
Fair value of equity issued to creditors, excluding equity issued to existing equity holders		(653,212)
Payment of Silo contract settlement		(7,228)
Gain on settlement of liabilities subject to compromise		412,852
Payment on predecessor credit facility fees and remaining unaccrued 2016 STIP		(1,007)
Total reorganization items at emergence	$	411,845
Issuance of warrants to existing shareholders	$	(4,081)
Proceeds from ad hoc equity committee		7,500
Issuance of shares to existing shareholders		(26,828)
Total reorganization adjustments to retained deficit	$	388,436

(5) Represents the fair value of 20,356,071 shares of new common stock and 1,650,510 warrants issued upon emergence from bankruptcy on the Effective Date.

Fresh-Start Adjustments

(6) Fair value adjustments to proved and unproved oil and natural gas properties. A combination of the market and income approach were utilized to perform valuations. Included in this line items were adjustments to the fully-owned subsidiary, Rocky Mountain Infrastructure, LLC. Lastly, the accumulated depreciation was reset to zero in accordance with fresh-start accounting.

(7) Represents the reset of wells in progress with fair valuation of the associated reserves in proved property.

(8) Upon application of fresh-start accounting and due to the Company's emergence with no debt, the Company revalued its asset retirement obligations based upon comparable companies' credit-adjusted risk-free rates in accordance with *ASC 410 - Asset Retirement and Environmental Obligations.*

(9) Cancellation of Predecessor Company's common stock and additional paid-in capital.

(10) Adjustment to reset retained deficit to zero.

Reorganization Items, Net

Reorganization items represent liabilities settled, net of amounts incurred subsequent to the Chapter 11 filing as a direct result of the Plan, and are classified as Reorganization items, net in our statement of operations. The following table summarizes reorganization items recorded in the Current Predecessor Period (in thousands):

Gain on settlement of liabilities subject to compromise	$ 412,852
Payment on predecessor credit facility fees and remaining unaccrued 2016 STIP	(1,007)
Fresh-start valuation adjustments	(311,361)
Legal and professional fees and expenses	(34,335)
Write-off of debt issuance and premium costs	(6,156)
Make-whole payment on Senior Notes	(51,185)
Total reorganization items, net	$ 8,808

NOTE 17 - 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):

	Successor		Predecessor	
	Year Ended December 31, 2018	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
Acquisition[1]	$ 2,861	$ 5,383	$ 445	$ 97
Development[2][3]	304,197	106,449	10,780	31,209
Exploration	294	3,671	769	74
Total[4]	$ 307,352	$ 115,503	$ 11,994	$ 31,380

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(1) Acquisition costs for unproved properties for the year ended December 31, 2018, 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period were $2.5 million, $5.4 million, $0.4 million, and $0.1 million, respectively. There was $0.4 million in acquisition costs for proved properties for the year ended December 31, 2018 and no acquisition costs for proved properties for the 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period.

(2) Development costs include workover costs of $5.6 million, $4.3 million, $1.8 million, and $6.0 million charged to lease operating expense for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period, respectively.

(3) Includes amounts relating to asset retirement obligations of $(9.0) million, $8.3 million, $3.1 million, and $2.4 million for the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period, respectively.

Suspended Well Costs

The Company did not incur any exploratory well costs during the Current Successor Period, 2017 Successor Period, 2017 Predecessor Period, and 2016 Predecessor Period.

Reserves

The proved reserve estimates at December 31, 2018 and 2017 were prepared by NSAI, our third party independent reserve engineers. The proved reserve estimate at December 31, 2016 was internally generated with an audit performed by NSAI. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

All of BCEI's oil, natural gas liquids, and natural gas reserves are attributable to properties within the United States. A summary of BCEI's changes in quantities of proved oil, natural gas liquids, and natural gas reserves for the years ended December 31, 2018, 2017, and 2016 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)
Balance-December 31, 2015	57.393	144.227	19.918
Extensions, discoveries and infills[1]	6.133	15.128	2.142
Production	(4.310)	(11.907)	(1.491)
Sales of minerals in place	(0.100)	(0.343)	(0.035)
Revisions to previous estimates[3]	(9.020)	(9.060)	(2.987)
Balance-December 31, 2016	50.096	138.045	17.547
Extensions, discoveries and infills[1]	8.470	22.212	3.376
Production	(3.081)	(9.010)	(1.136)
Revisions to previous estimates[3]	(2.557)	6.422	3.028
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)	(0.544)
Revisions to previous estimates[3]	4.555	8.219	0.101
Balance-December 31, 2018	64.354	165.012	24.930
Proved developed reserves:			
December 31, 2016	26.313	85.972	9.951
December 31, 2017	25.785	92.718	12.702
December 31, 2018	23.725	79.630	11.703
Proved undeveloped reserves:			
December 31, 2016	23.783	52.073	7.596
December 31, 2017	27.143	64.951	10.113
December 31, 2018	40.629	85.382	13.227

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(1) At December 31, 2018, horizontal development in the Wattenberg Field resulted in additions in extensions, discoveries, and infills of 28,832 MBoe.

At December 31, 2017, horizontal development in the Wattenberg Field resulted in additions in extensions and discoveries of 15,548 MBoe.

At December 31, 2016, horizontal development in the Wattenberg Field resulted in additions of 1,632 MBoe, and infill down-spacing within the Wattenberg Field resulted in 9,164 MBoe to the additions, extensions, and infills category.

(2) As of December 31, 2018, proved undeveloped reserves were reduced by 2,527 MBoe due to the removal of proved undeveloped locations from our five-year drilling program.

(3) As of December 31, 2018, the Company revised its proved reserves upward by 6,026 MBoe. 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 2,333 MBoe. In addition, lower operating cost estimates resulted in positive reserve adjustments of 1,536 MBoe. There were net positive engineering revisions of 2,163 MBoe.

As of December 31, 2017, the Company revised its proved reserves upward by 1,542 MBoe. The commodity prices at December 31, 2017 increased to $51.34 per Bbl WTI and $2.98 per MMBtu HH from $42.75 per Bbl WTI and $2.48 per MMBtu HH at December 31, 2016, resulting in positive revisions of 5,405 MBoe. In addition, lower operating cost estimates resulted in positive reserve adjustments (net of price increases) of 1,672 MBoe, of which 1,370 MBoe relate to operations in the Wattenberg Field. The Company also had positive other engineering revisions of 2,042 MBoe, offset by PUD demotions of 7,577 MBoe.

As of December 31, 2016, the Company revised its proved reserves downward by 13,517 MBoe. The commodity prices at December 31, 2016 decreased to $42.75 per Bbl WTI and $2.48 per MMBtu HH from $50.28 per Bbl WTI and $2.59 per MMBtu HH at December 31, 2015. The negative effects of commodity price reductions on reserves were offset by lower cost estimates to drill and complete future development locations in the Wattenberg Field along with lower operating cost estimates across the Company's operations, to reflect a positive reserves adjustment (net of price reductions) of 4,652 MBoe. Also, all future proved undeveloped locations in the Mid-Continent region were demoted to non-proved reserves resulting in a negative revision of 7,761 MBoe. In the Wattenberg Field, certain proved undeveloped locations totaling 8,611 MBoe were demoted due to their not being centric to current infrastructure. The Company also had negative other engineering revisions of 1,797 MBoe in 2016.

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

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits, and loss 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:

	For the Years Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Future cash flows	$ 4,742,180	$ 3,307,868	$ 2,424,415
Future production costs	(1,585,032)	(1,490,091)	(1,365,765)
Future development costs	(925,640)	(622,344)	(468,804)
Future income tax expense	—	—	—
Future net cash flows	2,231,508	1,195,433	589,846
10% annual discount for estimated timing of cash flows	(1,276,528)	(596,935)	(312,891)
Standardized measure of discounted future net cash flows	$ 954,980	$ 598,498	$ 276,955

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

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

	For the Years Ended December 31,		
	2018	2017	2016
(in thousands)			
Beginning of period	$ 598,498	$ 276,955	$ 327,816
Sale of oil and gas produced, net of production costs	(204,566)	(125,992)	(123,494)
Net changes in prices and production costs	365,952	282,112	(126,536)
Extensions, discoveries and improved recoveries	153,691	103,937	22,800
Development costs incurred	127,788	24,121	19,701
Changes in estimated development cost	(52,260)	2,122	281,062
Purchases of minerals in place	—	—	—
Sales of minerals in place	(115,742)	—	16
Revisions of previous quantity estimates	12,341	14,119	(182,938)
Net change in income taxes		—	—
Accretion of discount	59,850	27,696	32,782
Changes in production rates and other	9,428	(6,572)	25,746
End of period	$ 954,980	$ 598,498	$ 276,955

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2018, 2017, and 2016 were calculated using the twelve-month arithmetic average of first-day-of-the-month price inclusive of adjustments for quality and location.

	For the Years Ended December 31,		
	2018	2017	2016
Oil (per Bbl)	$ 59.29	$ 46.76	$ 38.42
Gas (per Mcf)	$ 2.28	$ 2.45	$ 2.07
Natural gas liquids (per Bbl)	$ 22.06	$ 19.57	$ 12.12

NOTE 18 - QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2018 and 2017 (in thousands, except per share data):

2018	Successor Three Months Ended March 31	Successor Three Months Ended June 30	Successor Three Months Ended September 30	Successor Three Months Ended December 31
Oil and gas sales	$ 64,193	$ 71,872	$ 74,380	$ 66,213
Operating profit[(1)]	$ 35,042	$ 40,014	$ 43,959	$ 41,416
Net Income	$ 13,870	$ 4,859	$ 43,363	$ 106,094
Basic net income per common share	$ 0.68	$ 0.24	$ 2.11	$ 5.16
Diluted net income per common share	$ 0.68	$ 0.24	$ 2.10	$ 5.15

	Predecessor		Successor		
2017	Three Months Ended March 31, 2017	April 1, 2017 through April 28, 2017	April 29, 2017 through June 30, 2017	Three Months Ended September 30, 2017	Three Months Ended December 31, 2017
Oil and gas sales	$ 52,559	$ 16,030	$ 28,114	$ 45,232	$ 50,189
Operating profit[(1)]	14,398	3,786	12,955	22,540	22,935
Net income (loss)	(94,276)	96,936	(3,580)	4,328	(5,768)
Basic net income (loss) per common share	$ (1.91)	$ 1.88	$ (0.18)	$ 0.21	$ (0.28)
Diluted net income (loss) per common share	$ (1.91)	$ 1.85	$ (0.18)	$ 0.21	$ (0.28)

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

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 April 19, 2017, we engaged Grant Thornton LLP ("Grant Thornton") on April 13, 2017 as the Company's new independent registered public accounting firm to audit the Company's financial statements for the fiscal year ending December 31, 2017, and dismissed Hein & Associates LLP ("Hein") as the Company's independent registered accounting firm. The decision to change the Company's independent registered accounting firm from Hein to Grant Thornton was approved by the Audit Committee of the Board of Directors of the Company.

During the fiscal years ended December 31, 2016 and December 31, 2015, and through April 13, 2017, there were no disagreements with Hein on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedures, that if not resolved to the satisfaction of Hein, would have caused Hein to make reference thereto in its reports on the Company's financial statements for such years.

During the fiscal years ended December 31, 2016 and 2015, and the subsequent interim period through April 13, 2017, 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, 2018. 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, 2018, 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, 2018, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control-Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2018, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

Grant Thornton 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, 2018, which is included in the consolidated financial statements in Item 8, Part II of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the year ended December 31, 2018 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Accounting Firm

Board of Directors and Stockholders
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. (a Delaware Company) and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in the 2013 Internal Control-Integrated Framework 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, 2018, based on criteria established in the 2013 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2018 and our report dated February 27, 2019 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/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 27, 2019

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, 2018.

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

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

The information required by this item 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, 2018.

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, 2018.

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, 2018.

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, 2018.

PART IV

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

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

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

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

SIGNATURES

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

BONANZA CREEK ENERGY, INC.

By: /s/ Eric T. Greager

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

February 27, 2019

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 27, 2019	By:	/s/ Eric T. Greager
			Eric T. Greager, President and Chief Executive Officer *(principal executive officer)*
Date:	February 27, 2019	By:	/s/ Brant DeMuth
			Brant DeMuth, Executive Vice President and Chief Financial Officer *(principal financial officer)*
Date:	February 27, 2019	By:	/s/ Sandi K. Garbiso
			Sandi K. Garbiso, *Vice President and Chief Accounting Officer* *(principal accounting officer)*
Date:	February 27, 2019	By:	/s/ Jack E. Vaughn
			Jack E. Vaughn, *Chairman of the Board*
Date:	February 27, 2019	By:	/s/ Paul Keglevic
			Paul Keglevic, *Director*
Date:	February 27, 2019	By:	/s/ Brian Steck
			Brian Steck, *Director*
Date:	February 27, 2019	By:	/s/ Thomas B. Tyree, Jr.
			Thomas B. Tyree, Jr., *Director*
Date:	February 27, 2019	By:	/s/ Scott D. Vogel
			Scott D. Vogel, *Director*
Date:	February 27, 2019	By:	/s/ Jeffrey E. Wojahn
			Jeffrey E. Wojahn, *Director*

INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Order Confirming Debtors' Third Amended Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code on April 7, 2017 (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 7, 2017)
2.2	Debtors' Third Amended Joint Prepackaged Plan of Reorganization Under Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 7, 2017)
2.3	Agreement and Plan of Merger, dated as of November 14, 2017, by and among Bonanza Creek Energy, Inc., SandRidge Energy, Inc. and Brook Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 15, 2017)
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).
10.1	Restructuring Support Agreement, dated as of December 23, 2016 (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on December 23, 2016)
10.2	Backstop Commitment Agreement, dated as of December 23, 2016 (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on December 23, 2016)
10.3	Stipulation dated February 1, 2017 among the Debtors, the Ad Hoc Noteholder Group and Silo (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on February 3, 2017)
10.4	Restructuring Support and Lock-Up Agreement, dated as of February 16, 2017, among the Debtors and the RBL Lenders (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed on March 16, 2017)
10.5	Amended and Restated Credit Agreement dated as of April 28, 2017, among Bonanza Creek Energy, Inc., as borrower, the lenders party thereto and KeyBank National Association, as administrative agent and as issuing lender (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017)
10.6	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)
10.7	Termination Agreement, dated as of December 28, 2017, by and among Bonanza Creek Creek Energy, Inc., SandRidge Energy, Inc. and Brook Merger Sub, Inc. (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K filed on December 28, 2017)
10.8*	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)
10.9*	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)
10.10*	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)
10.11*	Bonanza Creek Energy, Inc. Third Amended and Restated Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.6 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017)
10.12*	Bonanza Creek Energy, Inc. Fourth Amended and Restated Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 12, 2017)
10.13*	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)
10.14*	Separation and General Release Agreement dated as of June 11, 2017, by and between Bonanza Creek Energy, Inc. and Richard J. Carty (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 12, 2017)

10.15*	Form of Separation and General Release Agreement, by and between Bonanza Creek Energy, Inc. and Wade E. Jaques (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on August 4, 2017)
10.16*	Employment Letter Agreement dated November 6, 2017 between Bonanza Creek Energy, Inc. and Sandra Garbiso (incorporated by reference to Exhibit 10.2 of the Quarterly Report on Form 10 Q filed on November 9, 2017)
10.17*	Form of Employment Letter Agreement (incorporated by reference to Exhibit 10.2 of the Current Report on Form 8-K filed on March 29, 2013)
10.18*	Amendment No. 1 and Consent, dated as of December 22, 2017, to Amended and Restated Credit Agreement dated as of April 28, 2017 among Bonanza Creek Energy, Inc., as borrower, the lender parties thereto and KeyBank National Association, as administrative agent and as issuing lender.
10.19*	Amendment No. 2, dated as of February 2, 2018, to Amended and Restated Credit Agreement dated as of April 28, 2017 among Bonanza Creek Energy, Inc., as borrower, the lender parties thereto and KeyBank National Association, as administrative agent and as issuing lender
10.20*	Amendment No. 3, dated as of May 31, 2018, to Amended and Restated Credit Agreement dated as of April 28, 2017 among Bonanza Creek Energy, Inc., as borrower, the lender parties thereto and KeyBank National Association, as administrative agent and as issuing lender
10.21*	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)
10.22*	Credit Agreement, dated as of December 7, 2018, among Bonanza Creek Energy, In.c 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 From 8-K filed on December 10, 2018)
21.1†	List of subsidiaries
23.1†	Consent of Grant Thornton LLP
23.2†	Consent of Hein & Associates LLP
23.3†	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, Netherland, Sewell & Associates, Inc. for reserves as of December 31, 2018
101†	The following material from the Bonanza Creek Energy, Inc. Annual Report on Form 10-K for the year ended December 31, 2017 (and related periods), formatted in XBRL (Extensible Business Reporting Language) include (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations and Comprehensive Income, (iii) the Condensed Consolidated Statements of Stockholders' Equity, (iv) the Condensed Consolidated Statements of Cash Flows, and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text

____

* Management Contract or Compensatory Plan or Arrangement

† Filed or furnished herewith

Exhibit 21.1

Subsidiaries of Bonanza Creek Energy, Inc., a Delaware corporation

Bonanza Creek Energy Operating Company, LLC, a Delaware limited liability company

Holmes Eastern Company, LLC, a Delaware limited liability company

Rocky Mountain Infrastructure, LLC, a Delaware limited liability company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 27, 2019 with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Bonanza Creek Energy, Inc. on Form 10-K for the year ended December 31, 2018. We consent to the incorporation by reference of said reports in the Registration Statements of Bonanza Creek Energy, Inc. on Forms S-8 (File No. 333-229431 and File No. 333-217545).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 27, 2019

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement on Form S-8 (File Nos. 333-217545 and 333-229431) of Bonanza Creek Energy, Inc. of our report dated March 15, 2017, relating to our audit of the consolidated financial statements of Bonanza Creek Energy, Inc., appearing in the Annual Report on Form 10-K of Bonanza Creek Energy, Inc. for the year ended December 31, 2018.

Our report dated March 15, 2017, contains an explanatory paragraph that states that the Company suffered a significant deterioration in liquidity during 2016, and filed for bankruptcy under Chapter 11 of the Bankruptcy Code on January 4, 2017, which raises substantial doubt about the Company's ability to continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Hein & Associates LLP

Denver, Colorado
February 27, 2019

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, 2018. 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).

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 27, 2019

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, 2018 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 27, 2019

/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, 2018 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 27, 2019

/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, 2018 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 27, 2019

/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, 2018 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 27, 2019

/s/ Brant DeMuth

Brant DeMuth

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

January 18, 2019

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

Dear Mr. Wojahn:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2018, to the interest of Bonanza Creek Energy, Inc. and its wholly-owned direct and indirect subsidiaries (collectively, BCEI) in certain oil and gas properties located in Wattenberg Field, Colorado. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by BCEI. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for BCEI's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to BCEI interest in these properties, as of December 31, 2018, to be:

	Net Reserves			Future Net Revenue[(1)] (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	23,724.6	11,702.6	79,630.0	1,091,227.9	604,698.3
Proved Developed Non-Producing	0.0	0.0	0.0	-16.8	-15.4
Proved Undeveloped	40,629.1	13,226.7	85,381.6	1,140,297.1	350,297.1
Total Proved	64,353.7	24,929.3	165,011.6	2,231,508.1	954,980.1

Totals may not add because of rounding.

(1) Future net revenue is after deducting estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is BCEI's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for BCEI's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2018. For oil and NGL volumes, the average West Texas Intermediate spot price of $65.56 per barrel is adjusted for quality, transportation fees, and market differentials. Transportation fees are inclusive of reductions to oil purchase contracts that were negotiated in the context of BCEI's recent restructuring. No adjustments have been made to estimates of future revenue to account for any potential shortfall or deficiency in fulfilling these contracts. For gas volumes, the average Henry Hub spot price of $3.100 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $59.29 per barrel of oil, $22.06 per barrel of NGL, and $2.282 per MCF of gas.

Operating costs used in this report are based on operating expense records of BCEI. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and BCEI's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by BCEI and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are BCEI's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the BCEI interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on BCEI receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by BCEI, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from BCEI, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Benjamin W. Johnson, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2007 and has over 2 years of prior industry experience. John G. Hattner, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

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

By: /s/ Benjamin W. Johnson
Benjamin W. Johnson, P.E. 124738
Vice President

Date Signed: January 18, 2019

By: /s/ John G. Hattner
John G. Hattner, P.G. 559
Senior Vice President

Date Signed: January 18, 2019

BWJ:AHA

NETHERLAND, SEWELL
& ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) Acquisition of properties. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) 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.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) Bitumen. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) Condensate. Condensate is 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.

(5) Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) Developed oil and gas reserves. 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.

> Supplemental definitions from the 2018 Petroleum Resources Management System:
>
> Developed Producing Reserves – 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.
>
> Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. 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. 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.

(7) 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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.
(iv) Provide improved recovery systems.

(8) Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) 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.

(12) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) Exploratory well. An exploratory well is 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 as those items are defined in this section.

(14) Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

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

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) 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;
(C) 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:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, 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.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. 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.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) Production costs.

(i) 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.
(E) Severance taxes.

(ii) 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 cost of oil and gas produced along with production (lifting) costs identified above.

(21) Proved area. The part of a property to which proved reserves have been specifically attributed.

(22) 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

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

(23) Proved properties. Properties with proved reserves.

(24) 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% 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 EUR is much more likely to increase or remain constant than to decrease.

(25) Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) 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).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

> e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
> f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

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

(28) Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) Undeveloped oil and gas 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.

(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.

> From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):
>
> Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.
>
> Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:
>
> - The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
> - The company's historical record at completing development of comparable long-term projects;
> - The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
> - The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
> - The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(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.

(32) Unproved properties. Properties with no proved reserves.