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**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

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**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, 2017

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)

**410 17<sup>th</sup> Street, Suite 1400 Denver, Colorado**  
(Address of principal executive offices)

**61-1630631**

(I.R.S. Employer Identification No.)

**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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  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   
(Do not check if a smaller reporting 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, 2017, based upon the closing price of \$31.71 of the registrant's common stock as reported on the New York Stock Exchange, was approximately \$647,792,840. Excludes approximately 1,030 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 March 9, 2018: 20,453,619

**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, 2017, as incorporated by reference into Part III of this report for the year ended December 31, 2017.

**BONANZA CREEK ENERGY, INC.**  
**FORM 10-K**  
**FOR THE YEAR ENDED DECEMBER 31, 2017**

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### Information Regarding Forward-Looking Statements

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

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

- the Company’s business strategies and intent to maximize liquidity;
- 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;
- the Wattenberg Field being a premier oil and resource play in the United States;
- 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;
- 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 acreage;
- our ability to replace oil and natural gas reserves;

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- 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;

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

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

### **GLOSSARY OF OIL AND NATURAL GAS TERMS**

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

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

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

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

*"Asset Sale."* 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.

*"Central production facility."* Production facility for treating, gathering, storing and delivering oil, natural gas and water production from nearby wells.

*"Completion."* The process of treating a drilled well followed by the installation of permanent equipment to allow for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

*"Condensate."* A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

*“Developed acreage.”* The number of acres that are allocated or assignable to productive wells or wells capable of production.

*“Development costs.”* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves; (ii) drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly; (iii) acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

*“Development well.”* A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

*“Differential.”* The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead priced received.

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

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

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

*“ERISA.”* Employee Retirement Income Security Act of 1974.

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

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

*“Extension well.”* A well drilled to extend the limits of a known reservoir.

*“Field.”* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural

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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.

“*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

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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.



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- (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 that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
  - (a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
  - (b) The project has been approved for development by all necessary parties and entities, including governmental entities.
- (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

*“Proved undeveloped reserves” or “PUD.”* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

*“PV-10.”* A non-GAAP financial measure that represents inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices (after adjustment for differentials in location and quality) for each of the preceding twelve months. Please refer to the footnote 2 of the Proved Reserves table in Item 1 of this Annual Report on Form 10-K for additional discussion.

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

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*"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.

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“*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 United States. Bonanza Creek Energy, Inc. was incorporated in Delaware on December 2, 2010 and went public in December 2011.

Our oil and liquids-weighted assets are concentrated primarily in the Wattenberg Field in Colorado. We also own and operate oil-producing assets in the Dorcheat Macedonia Field and the McKamie Patton Field in southern Arkansas and the North Park Basin in Colorado. We operate approximately 92% of all our productive wells allowing us to control the pace, costs and completion techniques used in the development of our asset base. The Wattenberg Field has a low cost structure, strong production efficiencies, established reserves and prospective drilling opportunities, which allows for predictable production and reserve growth.

#### 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 Bankruptcy Court. The Debtors received bankruptcy court confirmation of their Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017 (the “Effective Date”). For additional information about our bankruptcy proceedings and emergence, see *Note 2 - 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, see *Note 3 - 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 “Current Successor Period” relates to the period of April 29, 2017 through December 31, 2017. References to “Current Predecessor Period” relate to the period of January 1, 2017 through April 28, 2017. References to “Prior Predecessor Period” relate to the period of January 1, 2016 through December 31, 2016.

#### Our Business Strategies

In 2017, the Company recapitalized its balance sheet, such that it is now well positioned to pursue its development strategy. This strategy consists of utilizing enhanced completion designs to increase the productivity of wells across our acreage position and securing our leasehold position in French Lake, which we expect to delineate in 2018. In order to focus on and partially fund the development of its core assets, the Company elected, subsequent to year-end, to actively pursue the divestment of its Mid-Continent region and North Park Basin assets. The Company successfully sold its North Park Basin on March 9, 2018 for \$0.1 million and full release of all current and future obligations.

We also took steps to improve our access to gas processing in the DJ Basin, which will result 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. 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.

During 2017, we implemented a series of cost reductions that are anticipated to be fully realized by the beginning of 2019 and result in annualized G&A and LOE reductions of approximately \$20.0 million. The cost reductions were focused

primarily around labor, compression contracts, water services, and well servicing. Further efficiency improvements will continue to be a focus for the Company, with our per-unit costs benefiting from production growth in 2018 and beyond.

In 2018, the Company plans to accelerate 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 will vary to ensure that thorough knowledge can be applied to future drilling programs. Fluid volumes and types, proppant volumes and types, stage spacing, well spacing, and flowback technique are the primary variables that will be tested throughout the 2018 program. The Company will continue to monitor industry trends, public data, and information from non-operated wells to further delineate optimum completion techniques. The program contemplates running one rig in the first half of 2018 with a second rig added at mid-year to coincide with its access to additional gas processing capacity. The 2018 program is expected to grow Wattenberg annual production by approximately 20% in 2018 and greater than 50% in 2019, assuming a continuous two rig program.

Capital investment with the 2018 program is expected to be approximately \$280.0 million to \$320.0 million, which will support drilling 90 gross wells and turning online 55 gross wells.

In order to help achieve the Company's strategies, we are actively seeking to secure permanent leadership.

The following tables summarize our estimated proved reserves, PV-10 reserve value, sales volumes, and projected capital spend as of December 31, 2017:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
<b>Developed</b>				
Rocky Mountain	19,419	71,212	11,107	42,396
Mid-Continent	6,366	21,506	1,595	11,544
	25,785	92,718	12,702	53,940
<b>Undeveloped</b>				
Rocky Mountain	27,143	64,951	10,113	48,082
Mid-Continent	—	—	—	—
	27,143	64,951	10,113	48,082
<b>Total Proved</b>	<b>52,928</b>	<b>157,669</b>	<b>22,815</b>	<b>102,022</b>

	Estimated Proved Reserves at December 31, 2017 <sup>(1)</sup>				Sales Volumes for the Year Ended December 31, 2017			Net Proved Undeveloped Drilling Locations as of December 31, 2017
	Total Proved (MBoe)	% of Total	% Proved Developed	PV-10 (\$ in MM) <sup>(2)</sup>	Average Net Daily Sales Volumes (Boe/d)	% of Total	Projected 2018 Capital Expenditures (\$ in millions)	
Rocky Mountain	90,478	89%	47%	\$ 484.8	12,783	80%	\$ 280-320	155.5
Mid-Continent <sup>(3)</sup>	11,544	11%	100%	113.7	3,213	20%	—	—
Total	102,022	100%	53%	\$ 598.5	15,996	100%	\$ 280-320	155.5

- (1) Proved reserves and related future net revenue and PV-10 were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices for each of the preceding twelve months, which were \$51.34 per Bbl WTI and \$2.98 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of \$4.58 per Bbl for crude oil and a decrease of \$0.53 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

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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 3,213 Boe/d for 2017, which is comprised of 2,885 Boe/d of production net to our interest and 328 Boe/d sales volumes from our percentage-of-proceeds contracts.

### **Our Operations**

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

#### ***Rocky Mountain Region***

The two areas in which we operate in the Rocky Mountain region are the Wattenberg Field in Weld County, Colorado and the North Park Basin in Jackson County, Colorado. As of December 31, 2017, our estimated proved reserves in the Rocky Mountain region were 90,478 MBoe, which represented 89% of our total estimated proved reserves and contributed 12,783 Boe/d, or 80%, of sales volumes during 2017.

*Wattenberg Field - Weld County, Colorado.* Our operations are located in the oil and liquids-weighted extension area of the Wattenberg Field targeting the Niobrara and Codell formations. As of December 31, 2017, our Wattenberg position consisted of approximately 95,000 gross (67,000 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 in the early stages of delineation.

Our estimated proved reserves at December 31, 2017 in the Wattenberg Field were 90,236 MBoe. As of December 31, 2017, we had a total of 625 gross producing wells, of which 447 were horizontal wells, and our sales volumes during 2017 were 12,719 Boe/d. Our sales volumes for the fourth quarter of 2017 were 11,916 Boe/d. As of December 31, 2017, our working interest for all producing wells averaged approximately 80% and our net revenue interest was approximately 66%.

We drilled and participated in drilling 59.5 gross (31.8 net) standard reach lateral ("SRL") equivalent wells in 2017 in the Wattenberg Field. As of December 31, 2017, we have an identified drilling inventory of approximately 205 gross (155.5 net) proved undeveloped ("PUD") drilling locations (248 gross SRL equivalents) on our acreage.

During the year, in the Niobrara benches, we drilled eight gross extended reach lateral ("XRL") operated wells and nine gross SRL operated wells, and we completed four gross XRL operated wells and five gross SRL operated wells. In addition, we drilled and completed one gross Codell SRL operated well. We also participated in the drilling and completion of 15 gross (5.0 net) XRL wells and one gross (0.1 net) medium reach lateral ("MRL") well in the Niobrara formation. We also participated in the completion of six gross (0.01 net) SRL wells in the Niobrara formation. In addition, we participated in the drilling and completion of one gross (0.5 net) XRL well and the completion of one gross (0.002 net) SRL well in the Codell formation.

The Company entered into two third-party gas processor contracts recently, which reduced line pressures in the Company's RMI system resulting in improved production from both new and existing wells, and will allow flexibility in moving gas to the most advantageous locations and provide additional production flow assurance.

The Company anticipates running one rig in the first half of 2018 with a second rig added at mid-year. The first rig is planned to drill large scale pads of up to eight wells throughout our legacy acreage position. At least two of the pads drilled in the first half of the year will be completed using slick-water completion designs to further test and validate the improved performance compared to historic gel completion designs. One of these pads is located in the western legacy acreage with the

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second pad located in the eastern legacy acreage. Data gathered from these tests will help formulate completion designs in the back half of the year and beyond. The addition of the second rig will provide additional data to form completion techniques and development assumptions throughout the acreage position going forward. 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.

The 2018 program is expected to grow Wattenberg annual production by approximately 20% in 2018 and greater than 50% in 2019, assuming a continuous two rig program.

Capital investment with this program is expected to be approximately \$280.0 million to \$320.0 million, which will support drilling 90 gross wells and turning online 55 gross wells in 2018. Of the wells planned to be drilled, approximately 43 are XRL wells, seven are MRL wells, and 40 are SRL wells. The cost of an XRL, MRL, and SRL well is anticipated to be \$5.4 million, \$4.2 million, and \$3.0 million, respectively.

*North Park Basin - Jackson County, Colorado.* We control approximately 20,000 gross (15,000 net) acres in the North Park Basin in Jackson County, Colorado, all prospective for the Niobrara oil shale. We operate the North and South McCallum Fields, which currently produce light oil, which is trucked to market.

In the North Park Basin, our estimated proved reserves as of December 31, 2017 were approximately 242 MBoe, consisting of 100% crude oil, and our sales volumes during 2017 were 64 Boe/d. Our sales volumes in the North Park Basin for the fourth quarter of 2017 were 57 Boe/d. There were no wells drilled during 2017 in the North Park Basin.

The Company successfully sold its North Park Basin on March 9, 2018 for \$0.1 million and full release of all current and future obligations.

### ***Mid-Continent Region***

In southern Arkansas, we target the oil-rich Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton Fields. As of December 31, 2017, our estimated proved reserves in the Mid-Continent region were 11,544 MBoe. We currently have 300 gross producing vertical wells. During 2017, no wells were drilled in the Mid-Continent region; however, the Company recompleted 25 wells in the Cotton Valley formation. We achieved a sales volume rate for 2017 of 3,213 Boe/d, of which 70% was from oil and NGLs, and a sales volume rate for the fourth quarter of 2017 of 2,778 Boe/d. None of our 2018 capital budget is assigned to the Mid-Continent region.

*Dorcheat Macedonia.* In the Dorcheat Macedonia Field, we average an approximate 87% working interest and an approximate 72% net revenue interest on all producing wells. The majority of our acreage is held by unitization or production. Our production during 2017 was approximately 2,660 Boe/d (2,988 Boe/d sales volumes). During the fourth quarter of 2017, our production was 2,251 Boe/d (2,595 Boe/d sales volumes). Our proved reserves in this field are approximately 10,419 MBoe. Due to the Company having no current plans to drill within the Mid-Continent region, no PUDs have been assigned to this region.

*Other Mid-Continent.* We own additional interests in the McKamie Patton Field in the Mid-Continent region near the Dorcheat Macedonia Field. As of December 31, 2017, our estimated proved reserves were approximately 1,125 MBoe, and sales volumes during 2017 were approximately 225 Boe/d. During the fourth quarter of 2017, our production was 183 Boe/d.

*Gas Processing Facilities.* Our Mid-Continent gas processing facilities are located in Lafayette and Columbia counties in Arkansas and are strategically located to serve our production in the region. Our McKamie Gas Plant has been idle since 2015, and our Dorcheat Macedonia Field Gas Plant has a current capacity of 12.5 MMcf/d with 28,000 gallons per day of associated NGL capacity. Our ownership of these facilities and related gathering pipeline provides us with the benefit of controlling processing and compression of our natural gas production.

### **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, 2017, 2016 and 2015 were determined using the preceding twelve month

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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, 2017, 2016 and 2015 for each of the regions and currently producing fields in which we operate. The proved reserve estimates as of December 31, 2017 were prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), our third-party independent reserve engineers. The proved reserves as of December 31, 2016 and 2015 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,		
	2017	2016	2015
	(MMBoe)		
Rocky Mountain	<b>90.5</b>	<b>78.0</b>	<b>80.1</b>
Wattenberg	90.3	77.8	79.8
North Park	0.2	0.2	0.3
Mid-Continent	<b>11.5</b>	<b>12.7</b>	<b>21.2</b>
Dorcheat Macedonia	10.4	11.6	20.1
McKamie Patton	1.1	1.1	1.1
Total	<b>102.0</b>	<b>90.7</b>	<b>101.3</b>

The following table sets forth more information regarding our estimated proved reserves at December 31, 2017, 2016 and 2015:



	At December 31,		
	2017	2016	2015
<b>Reserve Data<sup>(1)</sup>:</b>			
Estimated proved reserves:			
Oil (MMBbls)	52.9	50.1	57.4
Natural gas (Bcf)	157.7	138.0	144.2
Natural gas liquids (MMBbls)	22.8	17.5	19.9
Total estimated proved reserves (MMBoe) <sup>(2)</sup>	102.0	90.7	101.3
Percent oil and liquids	74%	75%	76%
Estimated proved developed reserves:			
Oil (MMBbls)	25.8	26.3	28.9
Natural gas (Bcf)	92.7	86.0	77.5
Natural gas liquids (MMBbls)	12.7	10.0	10.4
Total estimated proved developed reserves (MMBoe) <sup>(2)</sup>	53.9	50.6	52.2
Percent oil and liquids	71%	72%	75%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	27.1	23.8	28.5
Natural gas (Bcf)	65.0	52.0	66.7
Natural gas liquids (MMBbls)	10.1	7.5	9.6
Total estimated proved undeveloped reserves (MMBoe) <sup>(2)</sup>	48.1	40.1	49.2
Percent oil and liquids	77%	78%	77%

(1) Proved reserves were calculated using the preceding twelve month unweighted arithmetic average of the first-day-of-the-month prices, which were \$51.34 per Bbl WTI and \$2.98 per MMBtu HH, \$42.75 per Bbl WTI and \$2.48 per MMBtu HH, and \$50.28 per Bbl WTI and \$2.59 per MMBtu HH for the years ended December 31, 2017, 2016 and 2015, 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, 2017 reserve report are included in our development plan and are scheduled to be drilled within five years from their initial proved booking date. Upon emergence from bankruptcy, the Company undertook a process to review its five-year development schedule in light of improved commodity pricing and the significant improvement in the Company's liquidity and outstanding long-term debt and determined that all PUDs would in fact be drilled within the five-year allotted window. The Company's management evaluated the proved undeveloped drilling plan using NYMEX strip prices, the liquidation model for general and administrative costs and the cash flows from potential asset sales, wells scheduled to be drilled and from existing properties. Upon emergence from bankruptcy, the Company made the election to reset the five-year rule on its existing PUDs. The reserve report factored in a one-rig program until the second half of 2022, when a second-rig is added, which allows all PUDs to be drilled within the allotted five-year window. Subsequent to year-end, the Company approved a second rig to be added at mid-year 2018. All of the PUDs at December 31, 2017 reside in the Wattenberg field. The reliable technologies used to establish our proved reserves are a combination of pressure performance, geologic mapping, offset productivity, electric logs, and production data.

Estimated proved reserves at December 31, 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 are attributed to the Rocky Mountain region, and 99.8% of the Rocky Mountain proved reserves are attributed to the Wattenberg Field. The net increase in our reserves of 11.3 MMBoe is 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

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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 from December 31, 2016 to December 31, 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 is 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 is the result of completing 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 are on the 2018 rig schedule, offset by PUD locations that were removed due to a shift within our development strategy.

As of December 31, 2017, the current total proved undeveloped location count in our Wattenberg Field was 205 (248 SRL equivalents), compared to 210 (226 SRL equivalents) as of December 31, 2016. Our five-year plan includes the drilling of these proved undeveloped locations. The year-end 2017 reserves were based on a one-rig drilling program estimated to convert 19% of our year-end 2017 proved undeveloped reserves in the Wattenberg Field. Subsequent to year-end, the Company approved a second rig to be added at mid-year 2018. New drilling in 2018 will begin around existing central production facilities (“CPFs”) as they can be connected immediately upon completion. For the year ending December 31, 2017, approximately 50% of the proved undeveloped locations are spaced on 80 acres within a single bench and approximately 50% 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.

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 is 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 completing 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 was 204 as of December 31, 2015.

Total Company positive engineering revisions as of December 31, 2015, were 37,174 Mboe, of which 30,086 Mboe (81%) related to reserve changes in the Wattenberg Field. This positive engineering revision was offset by a negative pricing revision of 21,417 Mboe in the Wattenberg Field. The majority of the positive revisions in the Wattenberg Field resulted from a combination of decreased drilling and completion costs, including \$3.0 million per standard reach lateral well as of December 31, 2015 compared to \$4.2 million at December 31, 2014, a 29% decrease, and an increase in productivity from horizontal proved developed producing wells, which increased the offsetting proved undeveloped reserves. The increase in PDP reserves was primarily attributed to the installation of infrastructure in the east side of our Wattenberg Field acreage, which removed the producing constraint that inhibited productivity over the prior two years of development in that area. Another significant contribution to the positive reserve revision in the Wattenberg Field results from a contract change as of January 1, 2015, which gave our Company ownership of the natural gas liquids from our gas production. This conversion from two-stream (wet gas and oil) to three-stream (dry gas, natural gas liquids and oil) added 8,560 Mboe to our proved reserves as of December 31, 2015. With the addition of 45 horizontal proved undeveloped locations in the Wattenberg Field to the proved reserves at

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December 31, 2015, the total proved undeveloped location count as of December 31, 2015 was 204 (220 standard reach lateral equivalents) and was 226 as of December 31, 2014. A negative pricing revision of 28,810 Mboe for the Company resulted from a decrease in average commodity price from \$94.99 per Bbl WTI and \$4.35 per MMBtu HH for the year ended December 31, 2014 to \$50.28 per Bbl WTI and \$2.59 per MMBtu HH for the year ended December 31, 2015.

*Reconciliation of PV-10 to Standardized Measure*

PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. 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, 2017, 2016 and 2015:

	December 31,		
	2017	2016	2015
	(in millions)		
PV-10	\$ 598.5	\$ 276.9	\$ 327.8
Present value of future income taxes discounted at 10% <sup>(1)</sup>	—	—	—
Standardized Measure	\$ 598.5	\$ 276.9	\$ 327.8

(1) The tax basis of our oil and gas properties as of December 31, 2017, 2016, and 2015 provides more tax deduction than income generated from our oil and gas properties when the reserve estimates were prepared using \$51.34 per Bbl WTI and \$2.98 per MMBTU HH, \$42.75 per Bbl WTI and \$2.48 per MMBtu HH, and \$50.28 per Bbl WTI and \$2.59 per MMBtu HH, respectively.

*Proved Undeveloped Reserves*

	Net Reserves, MBoe		
	At December 31,		
	2017	2016	2015
Beginning of year	40,057	49,184	43,246
Converted to proved developed	(2,196)	(1,352)	(6,994)
Additions from capital program	11,717	—	2,308
Removed from capital program	(7,577)		
Acquisitions	—	—	1,541
Revisions	6,081	(7,775)	9,083
End of year	48,082	40,057	49,184

At December 31, 2017, our proved undeveloped reserves were 48,082 MBoe, all of which are 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 are on the 2018 rig schedule, offset by PUD locations that were removed due to a changes in our development strategy. The increase in revisions is 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

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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 is now focused entirely on the Wattenberg Field. Thirty-eight Wattenberg proved undeveloped locations that were not within areas with existing CPFs were demoted and were replaced with 42 infill proved undeveloped locations that are near existing CPFs which contributes to development well planning.

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

### *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, 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 Senior Reservoir Development Engineer who has over 17 years of experience in the oil and gas industry, including three 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 years ended December 31, 2016 and 2015 the Company prepared the reserves estimates, which were 100% audited by NSAI. The responsibility for compliance in reserves estimation was delegated to our internal corporate reservoir engineering group managed by John E. Vorwerk. Mr. Vorwerk was our Corporate Reserves Manager until August 2017. Mr. Vorwerk attended the Colorado School of Mines and graduated in 1976 with a Bachelor of Science degree in Geological Engineering. He also received a Master of Science degree in Mineral Economics from the Colorado School of Mines in 1991. Mr. Vorwerk had been in the petroleum industry for 41 years, and had been a Registered Professional Engineer since 1981. He had been directly involved in evaluations and the estimation of reserves and resources, and has worked in the corporate reserves function for over 21 years. Mr. Vorwerk was employed at Bonanza from 2014 until 2018, and served as Corporate Reserves Manager. During this time our internal corporate reservoir engineering group was responsible for compliance in reserve estimation, and our internal corporate reservoir engineering group, collectively with Mr. Vorwerk, had over 85 years of industry experience.

### *Independent Reserve Engineers*

The reserves estimates for the year ended December 31, 2017 shown herein have been independently prepared by NSAI. The reserve estimates for the years ended December 31, 2016 and 2015 were independently audited by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Benjamin W. Johnson and Mr. John 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, Geology (No. 559), has been practicing consulting petroleum geoscience at NSAI since 1991, and has over 11 years of prior industry

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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 have shown signs of rebounding during the latter part of 2017 and continuing into 2018. 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. With better pricing, we expect increased industry activity, which could moderate the magnitude of price increases throughout the year.

*Sensitivity Analysis*

If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 2% and our PV-10 value as of December 31, 2017 would decrease by approximately 28% or \$169.0 million. The PV-10 value of our Rocky Mountain region, primarily our Wattenberg assets, would decrease by 31% or \$148.3 million. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 1% and our PV-10 value as of December 31, 2017 would increase by approximately 27% or \$161.7 million. The PV-10 value of our Rocky Mountain region, primarily our Wattenberg assets, would increase by 29% or \$140.5 million.

The Company did not incur any impairments during 2017, and we do not anticipate triggering any impairments in 2018 when analyzing price changes only.

*Production*

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

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	Successor	Predecessor		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	For the Year Ended December 31, 2016	For the Year Ended December 31, 2015
<b>Oil:</b>				
Total Production (MBbls)	2,012.7	1,068.5	4,309.9	6,072.3
Wattenberg Field	1,568.5	834.4	3,470.7	5,029.6
Dorcheat Macedonia Field	379.9	193.2	750.0	923.2
Average sales price (per Bbl), including derivatives <sup>(3)</sup>	\$ 46.44	\$ 48.29	\$ 39.57	\$ 62.07
Average sales price (per Bbl), excluding derivatives <sup>(3)</sup>	\$ 47.18	\$ 48.29	\$ 35.32	\$ 40.95
<b>Natural Gas:</b>				
Total Production (MMcf)	5,767.5	3,242.5	11,906.3	14,110.9
Wattenberg Field	4,588.1	2,564.9	9,574.8	11,020.8
Dorcheat Macedonia Field	1,179.3	677.6	2,331.4	3,090.5
Average sales price (per Mcf), including derivatives <sup>(4)</sup>	\$ 2.29	\$ 2.57	\$ 1.76	\$ 1.95
Average sales price (per Mcf), excluding derivatives <sup>(4)</sup>	\$ 2.29	\$ 2.57	\$ 1.76	\$ 1.77
<b>Natural Gas Liquids:</b>				
Total Production (MBbls)	712.9	422.7	1,491.1	1,675.9
Wattenberg Field	656.2	391.1	1,354.3	1,489.9
Dorcheat Macedonia Field	56.8	31.6	136.8	186.0
Average sales price (per Bbl), including derivatives	\$ 18.38	\$ 17.52	\$ 12.39	\$ 9.49
Average sales price (per Bbl), excluding derivatives	\$ 18.38	\$ 17.52	\$ 12.39	\$ 9.49
<b>Oil Equivalents:</b>				
Total Production (MBoe)	3,686.9	2,031.6	7,785.4	10,100.0
Wattenberg Field	2,989.4	1,653.0	6,420.8	8,356.3
Dorcheat Macedonia Field	633.2	337.7	1,275.4	1,624.2
Average Daily Production (Boe/d)	15,048.4	16,930.4	21,271.7	27,671.2
Wattenberg Field	12,201.5	13,774.9	17,543.4	22,894.1
Dorcheat Macedonia Field	2,584.5	2,814.3	3,484.5	4,450.0
<b>Average Production Costs (per Boe)<sup>(1)(2)</sup></b>	\$ 9.28	\$ 8.20	\$ 7.25	\$ 7.56

(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 3,686.9 MBoe, 2,031.6 MBoe, 7,785.4 MBoe, and 10,100.0 MBoe for the Current Successor Period, Current Predecessor Period, and the Prior Predecessor Periods of 2016 and 2015, respectively. Total production volumes exclude volumes from our percentage-of-proceeds contracts in our Mid-Continent region of 77.9 MBoe, 41.9 MBoe, 150.1 MBoe, and 219.4 MBoe for the Current Successor Period, Current Predecessor Period, and the Prior Predecessor Periods of 2016 and 2015, respectively.

(3) Crude oil sales excludes \$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, Current Predecessor Period, and the Prior Predecessor Periods for 2016 and 2015, respectively.

(4) Natural gas sales excludes \$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, Current Predecessor Period and the Prior Predecessor Periods for 2016 and 2015, respectively.

**Principal Customers**

Three of our customers, NGL Crude Logistics, LLC, Lion Oil Trading & Transportation, Inc., and Duke Energy Field Services, comprised 44%, 18%, and 16%, respectively, of our total revenue for the year ended December 31, 2017. No other single non-affiliated customer accounted for 10% or more of our oil and natural gas sales in 2017. We believe the loss of any

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one customer would not have a material effect on our financial position or results of operations because there are numerous potential customers for our production.

**Delivery Commitments**

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 will be approximately 10,100 barrels per day and increases 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 \$154.5 million as of December 31, 2017. Please refer to *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, 2017.

	Oil <sup>(2)</sup>		Natural Gas <sup>(1)</sup>		Total <sup>(2)</sup>		Operated <sup>(2)</sup>	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	679	553.1	—	—	679	553.1	568	533.3
Mid-Continent	300	261.0	—	—	300	261.0	297	261.0
Total <sup>(2)</sup>	979	814.1	—	—	979	814.1	865	794.3

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

(2) Count came from internal production reporting system.

**Acreage**

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2017, broken down by the areas where we operate, along with the PV-10 values of each. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary.

	Developed Acres		Undeveloped Acres		Total Acres		PV-10
	Gross	Net	Gross	Net	Gross	Net	
	Rocky Mountain	76,565	62,451	37,716	19,334	114,281	
Wattenberg Field	61,882	50,629	32,812	16,369	94,694	66,998	483,769
Other Rocky Mountain	14,683	11,822	4,904	2,965	19,587	14,787	1,064
Mid-Continent	11,790	10,051	2,305	1,081	14,095	11,132	113,664
Dorcheat Macedonia Field	4,914	3,458	1,281	480	6,195	3,938	97,798
Other Mid-Continent	6,876	6,593	1,024	601	7,900	7,194	15,866
Total	88,355	72,502	40,021	20,415	128,376	92,917	\$ 598,497

**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. We focus primarily on the core fields of development where reserve bookings are prevalent. Decisions to let leasehold expire generally relate to areas outside of our core fields of development or when the expirations do not pose material impacts to development plans or reserves.

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The following table sets forth the number of net undeveloped acres by area as of December 31, 2017 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 2018		Expiring 2019		Expiring 2020	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	7,441	4,063	1,939	649	6,948	2,614
Mid-Continent	42	8	40	9	80	46
Total	7,483	4,071	1,979	658	7,028	2,660

**Drilling Activity**

The following table describes the exploratory and development wells we drilled and completed during the years ended December 31, 2017, 2016, and 2015.

	For the Years Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
<b>Exploratory</b>						
Productive Wells	—	—	—	—	—	—
Dry Wells	—	—	—	—	2	1.8
Total Exploratory	—	—	—	—	2	1.8
<b>Development</b>						
Productive Wells	4	4.0	4	3.9	92	76.1
Dry Wells	—	—	—	—	2	1.4
Total Development	4	4.0	4	3.9	94	77.5
<b>Total</b>	4	4.0	4	3.9	96	79.3

The following table describes the present operated drilling activities as of December 31, 2017.

	As of December 31, 2017	
	Gross	Net
<b>Exploratory</b>		
Rocky Mountain	—	—
Mid-Continent	—	—
Total Exploratory	—	—
<b>Development</b>		
Rocky Mountain	14	9.1
Mid-Continent	—	—
Total Development	14	9.1
<b>Total</b>	14	9.1

**Capital Expenditure Budget**

The Company contemplates running one rig in the first half of 2018 with a second rig added at mid-year. The capital budget for 2018 is expected to be approximately \$280.0 million to \$320.0 million, which will support drilling 90 gross wells and turning online 55 gross wells in 2018 all within the Rocky Mountain region. Of the wells planned to be drilled, approximately 43 are XRL wells, seven are MRL wells, and 40 are SRL wells. The costs of XRL, MRL, and SRL wells are anticipated to be \$5.4 million, \$4.2 million, and \$3.0 million, respectively. Actual capital expenditures could vary significantly



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based on, among other things, market conditions, commodity prices, drilling and completion costs, well results, and changes in the borrowing base under our successor credit facility.

**Derivative Activity**

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo-political factors that we can neither control or 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 31% of our projected 2018 production.

As of December 31, 2017, the Company had entered into the following commodity derivative contracts:

	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu
<b>1Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,000	\$53.20	6,000	\$3.36
<b>2Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,000	\$53.20	—	—
<b>3Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	2,000	\$51.96	—	—
<b>4Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	2,000	\$51.96	—	—
<b>1Q19</b>				
Cashless Collar	2,000	\$43.00/\$54.53	2,600	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q219</b>				
Cashless Collar	1,330	\$44.01/\$54.79	857	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q319</b>				
Swap	2,000	\$52.50	—	—
<b>Q419</b>				
Swap	2,000	\$52.50	—	—

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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)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu
<b>1Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,172	\$53.60	6,000	\$3.36
<b>2Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,500	\$54.26	—	—
<b>3Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	3,000	\$54.97	—	—
<b>4Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	2,000	\$51.96	—	—
<b>1Q19</b>				
Cashless Collar	2,000	\$43.00/\$54.53	2,600	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q219</b>				
Cashless Collar	1,330	\$44.01/\$54.79	857	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q319</b>				
Swap	2,000	\$52.50	—	—
<b>Q419</b>				
Swap	2,000	\$52.50	—	—

**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.

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Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 74% of our estimated proved reserves as of December 31, 2017 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2017, the daily NYMEX WTI oil spot price ranged from a high of \$60.46 per Bbl to a low of \$42.48 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of \$3.71 per MMBtu to a low of \$2.44 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. All of the jurisdictions in which we own or operate properties or assets for oil and natural gas production have 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 and 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 transportation of oil***

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

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

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

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

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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: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation more accessible to natural gas services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC’s NGA enforcement authority.

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

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

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

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

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our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

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

### ***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. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the spacing and unitization or pooling of oil and natural gas properties, the regulation of well spacing and well density, and procedures for proper plugging and abandonment of wells. The intent of these regulations is to promote the efficient recovery of oil and gas reserves while reducing waste and protecting correlative rights. 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, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

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

### ***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 the 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.

### ***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.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, 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

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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 and increased its civil penalty structure.

### *Air emissions*

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

For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all “other” fractured and refractured gas wells. These regulations also 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 NSPS and NESHAP rules from industry and the environmental community. As part of that reconsideration, in May 2016, the EPA issued revisions to the 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. On May 26, 2017, the EPA announced a 90-day stay of certain portions of the NSPS standards, which stay was vacated by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017. The EPA also proposed a two-year stay of the certain portions of the NSPS standards on June 12, 2017. In furtherance of this proposed stay, EPA released two notices of data availability that request information from industry in order to support the 2-year stay of certain requirements.

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 nonattainment 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. The DM/NFR area is at risk of being reclassified to “serious” non-attainment if it does not meet the 2008 NAAQS by 2018 or obtain an extension of the deadline from EPA. 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 costs and delays in obtaining necessary permits for new and significantly modified production facilities. A recent decision by the U.S.



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Court of Appeals for the D.C. Circuit also raises the possibility that both the 2008 and 2015 ozone NAAQS will remain in effect for a period of years, further complicating our future compliance and operations in ozone non-attainment areas.

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 or Arkansas 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 Denver Metro/North Front Range 8-hour Ozone Non-Attainment area (“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.

### *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 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. Depending on 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 is open until April 26, 2018. Following the comment period, EPA is expected to release a final rule.

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, per the terms of the Agreement, such a withdrawal may not be made until three years from the



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effective date of the Agreement, which is November 4, 2019, and any such withdrawal only becomes effective one year after the notice of withdrawal is provided.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce.

***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. The scope of what areas constitute jurisdictional waters of the United States regulated under the CWA is currently the subject of ongoing litigation and related administrative proceedings that are not expected to be resolved for several years. Additionally, in June 2016, 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 is designated was finalized in 2016. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

***Employee health and safety***

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (“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 have impact to our operations. These changes include among other items; record keeping and reporting, revised crystalline silica standard, 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 require that information be maintained concerning hazardous materials used or produced in our operations, and that this information be provided to employees, state and local government authorities and citizens.

***Hydraulic fracturing***

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

States have historically regulated oil and gas exploration and production activity, including hydraulic fracturing. State governments in the areas where we operate have adopted or are considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Such measures may address any risk to drinking water, the potential for hydrocarbon migration and disclosure of the chemicals used in fracturing.

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Colorado, for example, comprehensively updated its oil and gas regulations in 2008 and adopted significant additional amendments in 2011 and 2013. Among other things, the updated and amended regulations require operators to reduce methane emissions associated with hydraulic fracturing, compile and report additional information regarding 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, and implement additional groundwater testing. 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. 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.

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 are also considering additional regulation of hydraulic fracturing. The EPA has published guidance for issuing underground injection permits that would regulate hydraulic fracturing using diesel fuel. This guidance eventually could encourage other regulatory authorities to adopt permitting and other restrictions on the use of hydraulic fracturing. In addition, on October 21, 2011, the EPA announced its intention to propose regulations under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. 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. The EPA also has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act (“TSCA”) to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to the potential TSCA rulemaking. As also noted above, in January 2017, the EPA issued a proposed rule to include natural gas processing facilities in the 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. The Department of the Interior (the parent department of BLM) announced in October 2017 that it would delay the effective dates of the BLM venting and flaring rules that were to become effective in January 2018. Recently, a Federal district court in Northern California granted a preliminary injunction to prevent BLM’s stay of those effective dates. The rule is currently in effect, but is also subject to ongoing litigation and rulemaking, which could result in a rescission or substantial rewrite.

Apart from these ongoing federal and state initiatives, local governments are adopting 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. Any successful bans or moratoriums where we operate could increase the costs of our operations, impact our profitability, and even prevent us from drilling in certain locations.

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

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*Our use of hydraulic fracturing.* We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in both the Rocky Mountains and Mid-Continent.

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 via the 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.

### ***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.

### ***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 is 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, 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, and an increase in potential sanctions for COGCC rule’s 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 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

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rules requiring operators to register with and provide operational information to municipalities prior to conducting oil and gas operations with notice prior to engaging in certain 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 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 is substantially revising its oil and gas regulations in conjunction with a permitting moratorium that is about to expire. We do not expect that these local government regulations will have any material impact on our operation.

### **Employees**

As of December 31, 2017, we employed 156 people and also utilized the services of independent contractors to perform various field and other services. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages.

### **Offices**

As of December 31, 2017, we leased 63,783 square feet of office space in Denver, Colorado at 410 17<sup>th</sup> 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 field offices in Evans, Colorado and Magnolia, Arkansas.

### **Available information**

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

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

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

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

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

#### **Risks Related to Our Business**

***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, the borrowing base under our \$191.7 million revolving credit facility (the "successor credit facility"), access to capital, present value and quality of our reserves, the nature and scale of our operations and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. In recent years, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 74% of our estimated proved reserves as of December 31, 2017 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

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impairment charges due to commodity price declines. A prolonged period of low market prices for oil, natural gas and NGLs, like the current commodity price environment, or further declines in the market prices for oil and natural gas, will result in capital expenditures being further curtailed and will adversely affect our business, financial condition and liquidity and our ability to meet obligations, targets or financial commitments. During the year ended December 31, 2017, the daily New York Mercantile exchange (“NYMEX”) WTI oil spot price ranged from a high of \$60.46 per Bbl to a low of \$42.48 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of \$3.71 per MMBtu to a low of \$2.44 per MMBtu. As of March 9, 2018, the daily NYMEX WTI oil spot price and NYMEX natural gas HH spot price was \$62.04 per Bbl and \$2.73 per MMBtu, respectively.

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

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions from members of the Organization of Petroleum Exporting Countries and other oil producing nations;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- the price and availability of competitors’ supplies of oil and natural gas;
- technological advances affecting energy consumption;
- variability in subsurface reservoir characteristics, particularly in areas with immature development history;
- the availability of pipeline capacity and infrastructure; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under contracts at market-based prices. Declines in commodity prices may have the following effects on our business:

- reduction of our revenues, profit margins, operating income and cash flows;
- reduction in the amount of crude oil, natural gas and NGLs that we can produce economically and may lead to reduced liquidity and the inability to pay our liabilities as they come due;
- certain properties in our portfolio becoming economically unviable;
- delay or postponement of some of our capital projects;
- 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 successor credit facility or limitations in our access to sources of capital, such as equity or debt;
- declines in our stock price;
- refinery industry demand for crude oil;

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- storage availability for crude oil;
- 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, and we currently have approximately 31% of our anticipated 2018 production hedged. As a result, some of our future production will be sold at market prices, exposing us to the fluctuations in the price of oil and natural gas, unless we enter into new hedging transactions. 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 continued depressed price environment caused a reduction in our available liquidity. 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, therefore, sufficient 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 it 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

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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.

### ***Upon emergence from bankruptcy, the composition of our board of directors changed significantly.***

Pursuant to the reorganization plan, the composition of our board of directors changed significantly. Our board is made up of six directors, of which five had not previously served on our board. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on our board and, thus, may have different views on the issues that will determine our future. As a result, our future strategy and plans may differ materially from those of the past.

### ***The successor 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 successor 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 successor credit facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio, a maximum leverage ratio and a minimum interest coverage ratio. In addition, the successor credit facility contains covenants that, among other things, limit our ability:

- 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;
- enter into sale-leaseback transactions;
- consolidate, merge or transfer all or substantially all of our assets; and
- engage in certain business activities.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We would not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. As of the date of this Annual Report on Form 10-K, we are in compliance with all financial and non-financial covenants.



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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 successor credit facility. Our ability to comply with the financial ratios and financial condition tests under the successor 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 successor credit facility are limited by our borrowing base, which is subject to periodic redetermination.***

Beginning on April 1, 2018, the borrowing base under the successor credit facility will be redetermined at least semiannually and up to one additional time between scheduled determinations upon request of us or lenders holding 66 2/3% 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, 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 projects:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- unanticipated environmental liabilities;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as blizzards, ice storms, tomadoes, 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.***



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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, 2017, 2016 and 2015.

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

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

***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, 2017, 2016 and 2015, 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 sustained decrease in prices for oil, natural gas and NGLs, we have taken write-downs of the carrying value of our properties and may be required to take further write-downs if oil and natural gas prices remain depressed or decline further or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our drilling results.***

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, from time to time, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. Oil, natural gas and NGL prices have significantly declined since mid-2014 and have 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. Horizontal drilling 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 drilling program. Risks associated with our horizontal drilling program include, but are not limited to, the following, any of which could materially and adversely impact the success of our horizontal drilling program and thus, our cash flows and results of operations:

- successfully drilling and maintaining the wellbore to planned total depth;
- landing our wellbore in the desired drilling zone;
- effectively controlling the level of pressure flowing from particular wells;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the 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 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 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

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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 successor 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, 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 successor credit facility would be reduced. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

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

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

If the borrowing base under the successor credit facility 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 successor 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 a few core areas may increase our risk of production loss.***

Our assets and operations are concentrated in two core areas: the Wattenberg Field in Colorado and the Dorcheat Macedonia Field in southern Arkansas. These core areas currently provide approximately 98% of our current sales volumes and the vast majority of our development projects.

The Wattenberg and Dorcheat Macedonia Fields represent 80% and 19%, respectively, of our 2017 total sales volumes. Because our operations are not as diversified geographically as some of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including: fluctuations in prices of crude oil, natural gas and NGLs produced from wells in the area, accidents or natural disasters, restrictive governmental regulations and curtailment of production or interruption in the availability of gathering, processing or transportation infrastructure and services, and any resulting delays or interruptions of production from existing or planned new wells. Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide

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rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Wattenberg Field, we are subject to increasing competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages or delays. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

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

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

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

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

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

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

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

Approximately 47% of our total proved reserves were classified as proved undeveloped as of December 31, 2017. 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, groundwater and shoreline contamination;
- releases of natural gas and hazardous air pollutants or other substances into the atmosphere (including releases at our gas processing facilities);
- hazards resulting from the presence of hydrogen sulfide (H<sub>2</sub>S) or other contaminants in natural gas we produce;
- abnormally pressured formations resulting in well blowouts, fires or explosions;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- cratering (catastrophic failure);
- downhole communication leading to migration of contaminants;
- personal injuries and death; and
- natural disasters.

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

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

The presence of H<sub>2</sub>S, a toxic, flammable and colorless gas, is a common risk in the oil and gas industry and may be present in small amounts for brief periods from time to time at our well locations. Additionally, at one of our Arkansas properties, we produce a small amount of gas from four wells where we have identified the presence of H<sub>2</sub>S at levels that would be hazardous in the event of an uncontrolled gas release or unprotected exposure. In addition, our operations in Arkansas and Colorado are susceptible to damage from natural disasters such as flooding, wildfires, tornados 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.

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

Because hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if the operator is unaware of the pollution event and unable to report the “occurrence” to the insurance company within the required time frame. 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 their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.***

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. 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 drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking, and we may therefore be required to downgrade to probable or possible 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, the majority of our acreage in Arkansas was held by unitization, production, or drilling operations and therefore not subject to lease expiration. As

of the filing date of this report, approximately 10,425 net acres of our properties in the Rocky Mountain region 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 4,063 net acres will, unless otherwise extended, expire in 2018, approximately 649 net acres will expire in 2019, and approximately 5,713 net acres will expire in 2020 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. 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 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 face various risks associated with the long-term trend toward increased activism against oil and gas exploration and development activities.***

Opposition toward oil and gas drilling and development activity has been growing globally. 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.

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 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 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 the performance of 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.

In May 2016, the EPA issued amended New Source Performance Standards under the federal Clean Air Act (CAA). These regulations, known as “Quad Oa,” focused on achieving reductions in methane and volatile organic compound emissions at oil and natural gas operations. These rules, among other things, require leak detection and repair, additional control requirements for pneumatic controllers and pumps, and additional control requirements for oil well completions, gathering, boosting, and compressor stations. On May 26, 2017, the EPA announced a 90-day stay of certain portions of the Quad Oa standards, which stay was vacated in part by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017. The EPA also proposed a two-year stay of the certain portions of the Quad Oa standards on June 12, 2017, which stay is currently under consideration and the court emphasized is not impacted by its July 3, 2017 decision. At this point, we cannot predict the cost to comply with such air regulatory requirements or the timing of their implementation.

On December 17, 2014, the EPA proposed to revise and lower the existing 75 ppb National Ambient Air Quality Standard (NAAQS) for ozone under the CAA to a range within 65-70 ppb. On October 1, 2015, EPA finalized a rule lowering the standard to 70 ppb. This lowered ozone NAAQS could result in an expansion of ozone nonattainment areas across the United States, including areas in which we operate. In a related development, in 2015, the State of Colorado received a bump-up to its existing ozone non-attainment status from “marginal” to “moderate.” This increase in status will result in additional requirements under the CAA for the State of Colorado and will include a state rulemaking to implement such requirements.



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This rulemaking process started in early 2017 and is ongoing. Oil and natural gas operations in ozone nonattainment areas may be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

In February 2014, the Colorado Department of Public Health and Environment's Air Quality Control Commission (AQCC) finalized regulations imposing strict new requirements relating to air emissions from oil and gas facilities in Colorado that are even more stringent than comparable federal rules. These new Colorado rules include storage tank control, monitoring, recordkeeping and reporting requirements as well as leak detection and repair requirements for both well production facilities and compressor stations and associated equipment. These new requirements, which represent the first time a state has directly regulated methane emissions from the upstream oil and gas sector, have and will continue to impose additional costs on our operations.

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 Denver Metro/North Front Range 8-hour Ozone Non-Attainment area (DM/NFR area). In November 2017, in response to the recently published CTGs, the Colorado AQCC adopted additional air quality regulations that increased control, monitoring, recordkeeping, and reporting requirements on operations in the state.

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, and increased seismic activity. The federal government is studying the environmental risks associated with hydraulic fracturing and evaluating whether to adopt additional regulatory requirements. For example, the EPA has commenced a multi-year study of the potential impacts of hydraulic fracturing on drinking water resources, which was finalized in December 2016 and concludes drinking water resources can be affected by hydraulic fracturing under specific circumstances. In addition, in 2011, the EPA announced its intention to propose regulations under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. EPA finalized these rules on June 28, 2016 and extended the compliance date for these rules until August 29, 2019. The EPA also has issued guidance for issuing underground injection permits for hydraulic fracturing operations that use diesel fuel under the agency's Safe Drinking Water Act (SDWA) authority.

Moreover, the U.S. Department of the Interior finalized new rules for hydraulic fracturing activities on federal lands that, in general, would cover disclosure of fracturing fluid components, wellbore integrity, and handling of flowback water. The rule was stayed pending the outcome of litigation, but the 10th Circuit Court of Appeals dismissed the appeal from the decision vacating the rule and the underlying case on September 21, 2017 in light of the proposed rescission of those rules by the current administration. It is unclear whether the rule remains in effect, and industry groups have filed for a rehearing of the appeal. Responses to the rehearing requests were due on November 20, 2017. On December 29, 2017, the BLM issued a rescission of the hydraulic fracturing rule. BLM's rescission and the rule are also now the subject of ongoing litigation.

The BLM also proposed rules to address venting and flaring of methane on BLM land, which the U.S. House of Representatives has passed a bill to repeal, and the U.S. Occupational Safety and Health Administration has proposed stricter standards for worker exposure to silica, which would apply to use of sand as a proppant for hydraulic fracturing. Additionally, Department of the Interior (the parent department of BLM) announced in October 2017 that it would delay the effectiveness of the BLM methane rules that were to become effective in January 2018. Recently, a Federal district court in Northern California granted a preliminary injunction to prevent BLM's planned stay. The rule is currently in effect but is also subject to ongoing litigation and rulemaking, which could result in a rescission or substantial rewrite.

Apart from these ongoing federal initiatives, state governments where we operate have moved to impose stricter requirements on hydraulic fracturing and other aspects of oil and gas production. Colorado, for example, comprehensively updated its oil and gas regulations in 2008 and adopted significant additional amendments in 2011, 2014 and 2015. 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 to municipalities prior to conducting oil and gas operations with notice prior to engaging in certain operations. Colorado also finalized new rules regulating flowlines used in oil and gas operations on February 18, 2018. The new rules include: increased registration requirements, flowline design requirements, integrity management requirements, leak detection programs and requirements for abandoned flowlines.

In some instances certain 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 and doing business, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products and services. We cannot assure you that any such outcome would not be material, and any such outcome could have a material 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 services and the demand for and consumption of our products and services (due to potential changes in both costs and weather patterns).

In May 2016, the EPA promulgated rules 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 source, thereby triggering more stringent air permitting requirements.

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 report 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 Oa” 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 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 is open until April 26, 2018. Following the comment period, EPA is expected to release a final rule.

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 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.

***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, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. 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. These risks may be increased by the fact that we have not had a permanent chief executive officer since June 2017.***

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. Further, our ability to incentivize and retain senior management and key employees, as well as our ability to attract new senior management and key employees, may be harmed by the fact that we have not had a permanent chief executive officer since June 2017.

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 may in the future enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not 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.

***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 \$0.5 million at December 31, 2017, joint interest and other receivables of \$3.8 million at December 31, 2017 and the sale of our oil, natural gas and NGLs production of \$28.5 million in receivables at December 31, 2017, 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, 2017, sales to NGL Crude Logistics, LLC, Lion Oil Trading & Transportation, Inc., and Duke Energy Field Services comprised 44%, 18%, and 16%, respectively, of our total sales. Beginning in 2017 and continuing for seven years, we have contracted to sell all of our crude oil produced for a one-rig program 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 insurance contracts and bank lending commitments. We do not require most of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

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

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

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

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

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

***We are subject to federal, state, and local taxes, and may become subject to new taxes and certain federal income tax deductions 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 impose taxes on the oil and natural gas products we sell, and, 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.

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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 we are currently prohibited from paying, dividends on our common stock and, consequently, our stockholders' only opportunity to achieve a return on their investment is if the price of our stock appreciates.***

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our successor credit facility. Consequently, our stockholders' only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the 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 period between May 1, 2017 (the first trading day following our emergence from bankruptcy) and December 31, 2017, the sales price of our common stock ranged from a low of \$23.33 per share to a high of \$40.60 per share. The trading price of our common stock may be affected by a number of factors, including our bankruptcy proceeding, 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 on 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

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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.

***There is a limited trading market for our securities and the market price of our securities is subject to volatility.***

Upon emergence from bankruptcy, our common stock was canceled and we issued new common stock. The market price of the new common stock could be subject to wide fluctuations in response to, and the level of trading that develops with the new common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our new capital structure as a result of the transactions contemplated by the reorganization plan, our limited trading history subsequent to our emergence from bankruptcy, our limited trading volume, the concentration of holdings of our new common stock, the lack of comparable historical financial information due to our adoption of fresh-start accounting, actual or anticipated variations in our operating results and cash flow, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results.

***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 that of which we are aware.

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 has 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

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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 in excess of \$100,000 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 \$0.7 million in 2017 and currently anticipates spending \$3.5 million in 2018, and \$3.1 million for 2019 through 2022. The COC can be terminated after four years with a showing of substantial compliance and CDPHE approval.

**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". On March 9, 2018, the sale price of our common stock, as reported on the NYSE, was \$27.89 per share.

The high and low intra-day sale prices for our common stock for the Current Successor Period of April 29, 2017 through December 31, 2017 were as follows:

	<u>High</u>	<u>Low</u>
April 29, 2017 - June 30, 2017	\$ 40.60	\$ 27.79
3rd Quarter	\$ 34.42	\$ 23.33
4th Quarter	\$ 35.50	\$ 26.00

*Holdings.* As of March 9, 2018, 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 successor 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.

	<b>Total Number of Shares Purchased<sup>(1)</sup></b>	<b>Average Price Paid per Share</b>	<b>Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs</b>	<b>Maximum Number of Shares that May Be Purchased Under Plans or Programs</b>
April 29, 2017 - June 30, 2017	64,194	\$ 31.28	—	—
July 1, 2017 - September 30, 2017	11,480	\$ 27.11	—	—
October 1, 2017 - October 31, 2017	48	\$ 31.78	—	—
November 1, 2017 - November 30, 2017	—	\$ —	—	—
December 1, 2017 - December 31, 2017	—	\$ —	—	—
<b>Total</b>	<b>75,722</b>	<b>\$ 30.65</b>	<b>—</b>	<b>—</b>

(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 quarter ended December 31, 2017.



**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, 2013	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
<b>Statement of Operations Data:</b>						
Total operating net revenues <sup>(1)</sup>	\$ 421,860	\$ 558,633	\$ 292,679	\$ 195,295	\$ 68,589	\$ 123,535
Income (loss) from operations <sup>(1)</sup>	146,995	(47,506)	(907,444)	(129,110)	(1,600)	12,009
Net income (loss)	69,184	20,283	(745,547)	(198,950)	2,660	(5,020)
Basic net income (loss) per common share	\$ 1.72	\$ 0.50	\$ (15.57)	\$ (4.04)	\$ 0.05	\$ (0.25)
Basic weighted-average common shares outstanding	39,337	40,139	47,874	49,268	49,559	20,427
Diluted net income (loss) per common share	\$ 1.71	\$ 0.49	\$ (15.57)	\$ (4.04)	\$ 0.05	\$ (0.25)
Diluted weighted-average common shares outstanding	39,403	40,290	47,874	49,268	50,971	20,427
<b>Selected Cash Flow Data:</b>						
Net cash (used for) provided by operating activities	\$ 295,685	\$ 339,958	\$ 226,023	\$ 14,563	\$ (19,884)	\$ 27,574
Net cash used in investing activities	(453,893)	(837,232)	(452,573)	(67,401)	(5,904)	(82,648)
Net cash (used for) provided by financing activities	\$ 334,522	\$ 319,276	\$ 245,307	\$ 112,062	\$ 15,406	\$ (2,398)
<b>Sales Volumes:</b>						
Oil (MBbls) <sup>(2)</sup>	3,887.2	5,618.7	6,072.3	4,309.9	1,068.5	2,012.7
Natural gas (MMcf) <sup>(3)</sup>	9,975.9	15,395.8	14,551.1	12,231.3	3,336.1	5,938.0
Natural gas liquids (MBbls)	352.8	396.3	1,821.9	1,587.0	449.0	762.4
<b>Average Sales Price (before derivatives):</b>						
Oil (MBbls) <sup>(2)</sup>	\$ 91.84	\$ 81.95	\$ 40.95	\$ 35.31	\$ 48.29	\$ 47.18
Natural gas (MMcf) <sup>(3)</sup>	\$ 4.66	\$ 5.11	\$ 1.77	\$ 1.76	\$ 2.57	\$ 2.29
Natural gas liquids (MBbls)	\$ 51.74	\$ 49.14	\$ 9.49	\$ 12.39	\$ 17.52	\$ 18.38
<b>Average Sales Price (after derivatives):</b>						
Oil (MBbls)	\$ 88.82	\$ 84.00	\$ 62.07	\$ 39.57	\$ 48.29	\$ 46.44
Natural gas (MMcf)	\$ 4.70	\$ 5.16	\$ 1.95	\$ 1.76	\$ 2.57	\$ 2.29
Natural gas liquids (MBbls)	\$ 51.74	\$ 49.14	\$ 9.49	\$ 12.39	\$ 17.52	\$ 18.38
<b>Expense per BOE:</b>						
Lease operating expense and gas plant and midstream operating expense	\$ 8.09	\$ 8.44	\$ 7.40	\$ 7.12	\$ 8.04	\$ 9.09
Severance and ad valorem taxes	\$ 4.61	\$ 5.88	\$ 1.81	\$ 1.93	\$ 2.73	\$ 2.55
Depreciation, depletion, and amortization	\$ 23.75	\$ 26.66	\$ 23.73	\$ 14.01	\$ 13.54	\$ 5.66
General and administrative	\$ 9.40	\$ 9.51	\$ 6.81	\$ 9.71	\$ 7.28	\$ 11.34

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

(2) Crude oil sales excludes \$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, Current Predecessor Period and the Prior Predecessor Periods for 2016 and 2015, respectively.

(3) Natural gas sales excludes \$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, Current Predecessor Period and the Prior Predecessor Periods for 2016 and 2015, 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,				As of December 31, 2017
	2013	2014	2015	2016	
<b>Balance Sheet Data:</b>					
Cash and cash equivalents	\$ 180,582	\$ 2,584	\$ 21,341	\$ 80,565	\$ 12,711
Property and equipment, net (excludes assets held for sale)	1,267,249	1,756,477	922,344	1,018,968	774,082
Oil and gas properties held for sale, net of accumulated depreciation, depletion, and amortization	360	—	214,922	—	—
Total assets	1,541,812	1,990,086	1,259,641	1,134,478	830,371
Debt					
Predecessor credit facility	—	33,000	79,000	191,667	—
Senior Notes, net of unamortized premium and deferred financing costs	504,724	791,616	792,666	793,698	—
Total stockholders' equity	\$ 656,028	\$ 740,071	\$ 209,407	\$ 19,061	\$ 688,334
<b>Estimated Proved Reserves:</b>					
Oil (MMBbls)	43.6	54.7	57.4	50.1	52.9
Natural gas (Bcf)	139.6	188.6	144.2	138.0	157.7
Natural gas liquids (MMBbls)	2.9	3.4	19.9	17.5	22.8
Total proved reserves (MMBoe)	69.8	89.5	101.3	90.7	102.0

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

**Executive Summary**

We are a Denver-based exploration and production company focused on the extraction of oil and associated liquids-rich natural gas in the United States. Our oil and liquids-weighted assets are concentrated primarily in the Wattenberg Field in Colorado and the Dorcheat Macedonia Field in southern Arkansas.

**Bankruptcy Proceedings under Chapter 11**

On January 4, 2017, the Debtors filed voluntary petitions under Chapter 11 in the Bankruptcy Court. The Debtors received bankruptcy court confirmation of their Plan on April 7, 2017, and emerged from bankruptcy on April 28, 2017, the Effective Date. For additional information about our bankruptcy proceedings and emergence, see *Note 2 - 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, see *Note 3 - Fresh-Start Accounting*.

**Employment Modifications**

On June 5, 2017, our board of directors approved and the Company adopted the Fourth Amended and Restated Executive Change in Control and Severance Benefit Plan (the "Severance Plan"). The Severance Plan entitles certain executives and key employees to specific severance benefits and accelerated vesting of stock awards upon a qualifying termination from the Company. These benefits are subject to certain limitations including a reduction of the cash severance payment by the intrinsic value of the individual's unvested Management Incentive Plan awards (granted on the Effective Date) on a dollar-for-dollar basis.

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. Mr. Carty received accelerated vesting of the equity awards he was granted on the Effective Date, which awards were in accordance with the Plan and approved by the prior board of directors. The accelerated awards consisted of 137,814 non-qualified stock options with a \$34.36 strike price, which were forfeited as they had to be exercised within 90 days of the termination effective date, and 137,814 restricted stock units. The grant-date fair value of the options and restricted stock units was \$17.42 and \$34.36, respectively, resulting in a one-time non-cash stock-based compensation charge of \$7.1 million. The exercisable value of the equity grants on the effective date of termination was \$4.3 million. There was no cash severance provided in accordance with the terms of the Severance Plan.

During 2017, the Company implemented a series of cost reductions that included a reduction in workforce and operating expenses. These reductions resulted in one-time cash severance charges of approximately \$1.6 million and anticipated operating expense implementation fees of approximately \$2.0 million to \$3.0 million to be incurred in 2018. The anticipated annualized impact of this action is a reduction in recurring cash general and administrative expense of approximately \$10.0 million and operating expenses of \$10.0 million. The operating cost reductions will be implemented throughout the coming year and are anticipated to be fully realized by the beginning of 2019. The Company continues to review its costs to better align its cost structure with the current commodity price environment.

The Company is actively pursuing the permanent placement of leadership to carry out the planned growth and development plans of the Company.

**Financial and Operating Results**

Our 2017 financial and operational results include:

- Total liquidity of \$204.4 million at December 31, 2017, consisting of, year-end cash balance plus funds available under the successor credit facility, as compared with \$38.9 million, consisting of, the year-end cash balance net of the borrowing base deficiency under the predecessor credit facility at December 31, 2016. Please refer to *Liquidity and Capital Resources* below for additional discussion;

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- Increased proved reserves by 13% to 102.0 MMBoe as of December 31, 2017, from 90.7 MMBoe as of December 31, 2016;
- Decreased the go-forward annualized general and administrative and operating expenses by \$20.0 million;
- Full year capital expenditures were \$109.8 million;
- Entered into two new gas gathering and processing contracts in the Wattenberg Field allowing greater reliability, optionality and enhancement of our RMI system.

***Business Strategies and Outlook for 2018***

In 2018, the Company plans to accelerate development while testing enhanced completion designs on large-scale pads throughout the Company's acreage position, including delineating its French Lake leasehold. The program contemplates running one rig in the first half of 2018 with a second rig added at mid-year to coincide with additional gas processing capacity. The 2018 program is expected to grow Wattenberg annual production by approximately 20% in 2018 and greater than 50% in 2019, assuming a continuous two rig program. Allocated capital associated with this program is expected to be approximately \$280.0 million to \$320.0 million, which will support drilling 90 gross wells and turning online 55 gross wells in 2018.

In order to focus and partially fund its core asset development, the Company elected, subsequent to year-end, to actively pursue divesting of its Mid-Continent region and North Park Basin. The Company successfully sold its North Park Basin on March 9, 2018 for \$0.1 million and full release of all current and future obligations.

In order to help achieve the Company's strategies, we are actively seeking to secure permanent leadership.

**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.

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

	Successor	Predecessor	
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
<b>Operating Revenues:</b>			
Crude oil sales <sup>(1)</sup>	\$ 94,956	\$ 51,593	\$ 152,205
Natural gas sales <sup>(2)</sup>	13,605	8,584	21,470
Natural gas liquids sales	14,012	7,867	19,660
Product revenue	\$ 122,573	\$ 68,044	\$ 193,335
<b>Sales Volumes:</b>			
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) <sup>(3)</sup>	3,764.8	2,073.5	7,935.5
<b>Average Sales Prices (before derivatives):</b>			
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) <sup>(3)</sup>	\$ 32.56	\$ 32.82	\$ 24.36
<b>Average Sales Prices (after derivatives)<sup>(4)</sup>:</b>			
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) <sup>(3)</sup>	\$ 32.17	\$ 32.82	\$ 26.67

(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 Current Successor Period, Current Predecessor Period and the Prior 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 Current Successor Period, Current Predecessor Period and the Prior 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 was \$1.5 million and the derivative cash settlement gain was \$18.3 million for the Prior 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 are 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 completed 10.0 net operated wells in the Rocky Mountain region and no wells in the Mid-Continent region.

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

	Successor	Predecessor	
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016
<b>Operating Expenses:</b>			
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
<b>Selected Costs (\$ per Boe):</b>			
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 Current Successor and 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 Current 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 Current Successor and Predecessor Period from \$12.8 million for the Prior 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 is commensurate between the comparable periods.

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

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*Exploration.* Our exploration expense increased \$6.5 million to \$7.4 million for the Current Successor and Predecessor Period from \$0.9 million for the comparable period in 2016. During the Current Successor and Predecessor Period we paid \$3.8 million in delay rentals, incurred \$2.9 million on abandoned well projects and \$0.7 million in geological and geophysical expenses. During the Prior 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 Current Successor Period, Current Predecessor Period and Prior Predecessor Period. The Current 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 Current Successor and Predecessor Periods. During the Prior Predecessor Period, we incurred a \$10.0 million impairment charge on our Mid-Continent assets based on the most recent bid 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 Current Successor and Predecessor Periods. During the Prior 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 Current Successor Period. During the Current Predecessor Period, we incurred \$1.0 million in unused commitment fees on a water supply contract in the Wattenberg Field. During the Prior 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 see *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 Current Successor and Predecessor Periods. During the Prior Predecessor Period, we incurred a \$21.0 million loss to settle our crude oil purchase agreement with Silo 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 Current Successor Period, Current Predecessor Period and Prior Predecessor Period. The Current 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 Prior Predecessor Period includes \$13.3 million or \$1.68 per Boe more of advisor fees than the comparable period in 2017. Excluding those two items the per Boe metrics are commensurate between the periods presented.

*Derivative gain (loss).* Our derivative loss for the Current Successor Period was \$15.4 million. We had no derivative contracts during the Current Predecessor Period. During the Current Successor Period, we entered into several oil and gas costless collar and swap contracts. Our derivative loss is mainly due to fair market value adjustments caused by market prices being higher than our contracted hedge prices. Our derivative loss for the Prior 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 Prior 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 Current Successor Period, Current Predecessor Period and Prior Predecessor Period was \$0.8 million, \$5.7 million and \$62.1 million. 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 Current Successor Period. Interest expense on the Senior Notes was \$1.0 million and \$52.3 million for the Current Predecessor Period and Prior Predecessor Period, respectively, with the remaining interest expense relating to the predecessor credit facility. The Company had no outstanding debt during the Current Successor Period. Average debt outstanding for the Current Predecessor Period and Prior Predecessor Period was \$991.7 million and \$1.0 billion, respectively.

**Year Ended December 31, 2016 Compared to Year Ended December 31, 2015**

The table below presents predecessor revenues, sales volumes, and average sales prices for the years ended December 31, 2016 and 2015:

	For the Years Ended December 31,			
	2016	2015	Change	Percent Change
(In thousands, except percentages)				
<b>Operating Revenues:</b>				
Crude oil sales <sup>(1)</sup>	\$ 152,205	\$ 248,631	\$ (96,426)	(39)%
Natural gas sales <sup>(2)</sup>	21,470	25,689	(4,219)	(16)%
Natural gas liquids sales	19,660	17,289	2,371	14 %
Product revenue	<u>\$ 193,335</u>	<u>\$ 291,609</u>	<u>\$ (98,274)</u>	<u>(34)%</u>
<b>Sales Volumes:</b>				
Crude oil (MBbls)	4,309.9	6,072.3	(1,762.4)	(29)%
Natural gas (MMcf)	12,231.3	14,551.1	(2,319.8)	(16)%
Natural gas liquids (MBbls)	1,587.0	1,821.9	(234.9)	(13)%
Crude oil equivalent (MBoe) <sup>(3)</sup>	<u>7,935.5</u>	<u>10,319.4</u>	<u>(2,383.9)</u>	<u>(23)%</u>
<b>Average Sales Prices (before derivatives):</b>				
Crude oil (per Bbl)	\$ 35.31	\$ 40.95	\$ (5.64)	(14)%
Natural gas (per Mcf)	\$ 1.76	\$ 1.77	\$ (0.01)	(1)%
Natural gas liquids (per Bbl)	\$ 12.39	\$ 9.49	\$ 2.90	31 %
Crude oil equivalent (per Boe) <sup>(3)</sup>	\$ 24.36	\$ 28.26	\$ (3.90)	(14)%
<b>Average Sales Prices (after derivatives)<sup>(4)</sup>:</b>				
Crude oil (per Bbl)	\$ 39.57	\$ 62.07	\$ (22.50)	(36)%
Natural gas (per Mcf)	\$ 1.76	\$ 1.95	\$ (0.19)	(10)%
Natural gas liquids (per Bbl)	\$ 12.39	\$ 9.49	\$ 2.90	31 %
Crude oil equivalent (per Boe) <sup>(3)</sup>	\$ 26.67	\$ 40.95	\$ (14.28)	(35)%

- (1) Crude oil sales excludes \$0.5 million and \$0.2 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2016 and 2015, respectively.
- (2) Natural gas sales excludes \$1.5 million and \$0.8 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2016 and 2015, 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 and natural gas. For the years ended December 31, 2016 and 2015, the derivative cash settlement gain for oil contracts was \$18.3 million and \$128.3 million, respectively, and the derivative cash settlement gain for gas contracts was \$2.7 million for the year ended December 31, 2015. Please refer to *Part II, Item 8, Note 13 - Derivatives* for additional disclosures.

Revenues decreased by 34% to \$193.3 million for the year ended December 31, 2016 compared to \$292.7 million for the year ended December 31, 2015 largely due to a 23% decrease in sales volumes coupled with a 14% decrease in oil equivalent pricing. The decreased volumes are a direct result of the Company suspending all drilling and completion activities after the first quarter of 2016. During the period from December 31, 2015 through December 31, 2016, we completed 21 gross wells in the Rocky Mountain region and drilled and completed no wells in the Mid-Continent region.

The following table summarizes our operating expenses for the predecessor periods indicated:



	For the Years Ended December 31,			
	2016	2015	Change	Percent Change
	(In thousands, except percentages)			
<b>Operating Expenses:</b>				
Lease operating expense	\$ 43,671	\$ 65,038	\$ (21,367)	(33)%
Gas plant and midstream operating expense	12,826	11,368	1,458	13 %
Severance and ad valorem taxes	15,304	18,629	(3,325)	(18)%
Exploration	946	15,827	(14,881)	(94)%
Depreciation, depletion and amortization	111,215	244,921	(133,706)	(55)%
Impairment of oil and gas properties	10,000	740,478	(730,478)	(99)%
Abandonment and impairment of unproved properties	24,692	33,543	(8,851)	(26)%
Unused commitments	7,686	—	7,686	100 %
Contract settlement expense	21,000	—	21,000	100 %
General and administrative expense	77,065	70,319	6,746	10 %
Operating expenses	<u>\$ 324,405</u>	<u>\$ 1,200,123</u>	<u>\$ (875,718)</u>	<u>(73)%</u>
<b>Selected Costs (\$ per Boe):</b>				
Lease operating expense	\$ 5.50	\$ 6.30	\$ (0.80)	(13)%
Gas plant and midstream operating expense	1.62	1.10	0.52	47 %
Severance and ad valorem taxes	1.93	1.81	0.12	7 %
Exploration	0.12	1.53	(1.41)	(92)%
Depreciation, depletion and amortization	14.01	23.73	(9.72)	(41)%
Impairment of oil and gas properties	1.26	71.76	(70.50)	(98)%
Abandonment and impairment of unproved properties	3.11	3.25	(0.14)	(4)%
Unused commitments	0.97	—	0.97	100 %
Contract settlement expense	2.65	—	2.65	100 %
General and administrative expense	9.71	6.81	2.90	43 %
Operating expenses	<u>\$ 40.88</u>	<u>\$ 116.29</u>	<u>\$ (75.41)</u>	<u>(65)%</u>
Operating expenses, excluding impairments and abandonments, unused commitments and contract settlement expense	<u>\$ 32.89</u>	<u>\$ 41.28</u>	<u>(8.39)</u>	<u>(20)%</u>

*Lease operating expense.* Our lease operating expense decreased \$21.4 million or 33%, to \$43.7 million for the year ended December 31, 2016 from \$65.0 million for the year ended December 31, 2015 and decreased on an equivalent basis from \$6.30 per Boe to \$5.50 per Boe. The majority of the decrease is due to continued operating cost reductions along with decreased activity levels. The Company reduced operating costs and negotiated contract reductions resulting in decreased well servicing costs of \$10.1 million, compression costs of \$4.9 million and pumping and gauging costs of \$2.7 million during the year ended December 31, 2016 when compared to the same period in 2015.

*Gas plant and midstream operating expense.* Our gas plant and midstream operating expense increased \$1.5 million to \$12.8 million for the year ended December 31, 2016 from \$11.4 million for the year ended December 31, 2015 and increased on an equivalent basis from \$1.10 per Boe to \$1.62 per Boe. The increase in aggregate and on an equivalent basis is due to the start-up and continued buildout of RMI, which began in May of 2015.

*Severance and ad valorem taxes.* Our severance and ad valorem taxes decreased by 18%, or \$3.3 million to \$15.3 million for the year ended December 31, 2016 from \$18.6 million for the year ended December 31, 2015. Severance and ad valorem taxes primarily correlate to revenue. Revenues decreased by 33% for the year ended December 31, 2016 when compared to the same period in 2015, which was offset by a tax refund received during the third quarter of 2015.

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*Exploration.* Our exploration expense decreased \$14.9 million to \$0.9 million during the year ended December 31, 2016 from \$15.8 million for the year ended December 31, 2015. During the year ended December 31, 2016, we incurred minimal exploration charges. During the year ended December 31, 2015 we incurred charges of \$5.6 million and \$8.5 million for exploratory wells located in the North Park Basin and outside of our current development area in southern Arkansas, respectively, which we were unable to assign economic proved reserves. During 2015, we also paid \$1.0 million and \$0.7 million in geological and geophysical expenses and delay rentals, respectively.

*Depreciation, depletion and amortization.* Our depreciation, depletion and amortization expense decreased \$133.7 million, or 55%, to \$111.2 million for the year ended December 31, 2016 from \$244.9 million for the year ended December 31, 2015 and decreased on an equivalent basis from \$23.73 per Boe to \$14.01 per Boe. The Company realized significant proved property impairments during the fourth quarter of 2015 resulting in a 50% decrease in the net proved property depletable base from the year ended December 31, 2015 to December 31, 2016.

*Impairment of oil and gas properties.* For the year ended December 31, 2016 we incurred an impairment of proved properties of \$10.0 million, a \$730.5 million decrease from the year ended December 31, 2015. We impaired our Mid-Continent assets by \$10.0 million based on the most recent bid received during the first quarter of 2016, when it was held for sale. For the year ended December 31, 2015, we impaired our Mid-Continent assets by \$321.2 million due to their depressed fair value upon classification as held for sale and our Rocky Mountain assets by \$419.3 million due to low commodity prices. 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.* For the year ended December 31, 2016 we incurred an abandonment and impairment of unproved properties of \$24.7 million, an \$8.9 million decrease from the prior year. Our 2016 abandonment and impairment charges related to non-core leases expiring within the Wattenberg Field. During the year ended December 31, 2015, we incurred \$24.8 million of impairment charges relating to non-core leases expiring within the Wattenberg Field and \$8.7 million of impairment charges to fully impair the North Park Basin due to a strategic shift in our development plan.

*Unused commitments.* For the year ended December 31, 2016, we incurred \$7.7 million in unused commitment fees. During 2015, we did not incur any fees of this nature. The unused commitment fees in 2016 of \$4.3 million and \$3.4 million are the result of water commitment deficiency payments and purchase and transportation agreement deficiency payments, respectively. Please see *Note 8 - Commitments and Contingencies* in Part II, Item 8 of this Annual Report on Form 10-K for additional discussion.

*Contract settlement expense.* For the year ended December 31, 2016 we incurred a \$21.0 million loss to settle our crude oil purchase agreement with Silo as part of our bankruptcy process. There were no material settlements during 2015. 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 increased \$6.7 million, or 10%, to \$77.1 million for the year ended December 31, 2016 from \$70.3 million for the comparable period in 2015 and increased on an equivalent basis to \$9.71 per Boe from \$6.81 per Boe. The increase in general and administrative expense in 2016 on an aggregate and equivalent basis is due to \$20.4 million of advisory fees related to our restructuring efforts and an increase of \$1.2 million in severance payments. These cost increases were offset by a decrease in salaries and wages, including benefits of \$9.3 million and stock compensation of \$5.7 million due to reductions in workforce that have occurred since December 31, 2015.

*Derivative gain (loss).* Our derivative loss increased \$67.8 million to an \$11.2 million loss for the year ended December 31, 2016 from a gain of \$56.6 million for the comparable period in 2015. The decrease is related to a reduction of hedged volumes throughout 2016 and decreased contract prices at the time of conversion from three-way collars to swap and puts at the end of the first quarter of 2016 bringing them closer to realized prices during the year ended December 31, 2016 when compared to the same period in 2015. Please refer to *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 year ended December 31, 2016 increased 9% to \$62.1 million compared to \$57.1 million for the year ended December 31, 2015. The interest expense increase is a result of increased average debt outstanding for the year ended December 31, 2016 of \$1.0 billion, compared to \$847.9 million for the comparable period in 2015. Total interest expense is comprised primarily of interest expense attributable to the Senior Notes including amortization

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of the premium and financing costs, which was \$52.3 million and \$52.1 million for the years ended December 31, 2016 and 2015, respectively.

*Income tax benefit (expense).* Our estimate for federal and state income tax benefit for the years ended December 31, 2016 and 2015 was zero and \$164.9 million, respectively. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. Our effective tax rate for the years ended December 31, 2016 and 2015 was 0.0% and 18.1%, respectively. As of December 31, 2015, a full valuation was placed against the net deferred tax assets, which caused effective tax rate to differ from the U.S. statutory income tax rate.

**Liquidity and Capital Resources**

The successor Company's anticipated sources of liquidity include cash from operating activities, borrowings under the successor credit facility, proceeds from sales of assets and potential proceeds from capital market transactions. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for our crude oil, NGL and natural gas products, 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 and other supply chain dynamics, among other factors.

As of December 31, 2017, our liquidity was \$204.4 million, consisting of cash on hand of \$12.7 million and \$191.7 million of available borrowing capacity on the successor credit facility. As of the date of filing, we had \$15.0 million outstanding on our successor 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 the successor 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. Please refer to *Note 2 - Chapter 11 Proceedings and Emergence* for additional details.

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

	Successor	Predecessor		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Net cash (used in) provided by operating activities	\$ 27,574	\$ (19,884)	\$ 14,563	\$ 226,023
Net cash used in investing activities	(82,648)	(5,904)	(67,401)	(452,573)
Net cash (used in) provided by financing activities	(2,398)	15,406	112,062	245,307
Cash and cash equivalents	12,711	70,183	80,565	21,341
Acquisition of oil and gas properties	5,383	445	98	16,270
Exploration and development of oil and gas properties	76,375	5,123	52,344	425,918

*Cash flows provided by operating activities*

The Current Successor Period included cash receipts and disbursements attributable to our normal operating cycle. The Current Predecessor Period contained the reorganization costs along with our normal operating receipts and disbursements. The decrease in cash flows from operating activities between the year ended December 31, 2016 and December 31, 2015 resulted primarily from a 13% decrease in crude oil equivalent pricing and a 23% decrease in sales volumes and a \$112.7 million decrease in derivative cash settlements. 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 \$81.8 million, \$5.6 million, \$52.4 million and \$442.2 million for Current Successor Period, Current

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Predecessor Period, Prior Predecessor Periods for 2016 and 2015. The fluctuation in cash flows in investing activities is a direct result of the Company's entrance and emergence from bankruptcy.

### *Cash flows provided by financing activities*

Net cash used by financing activities for the Current Successor Period consisted of employee tax withholdings in exchanges for the return of common stock. Net cash provided by financing activities for the Current 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. Net cash provided by financing activities for the year ended December 31, 2015 consisted primarily of \$202.7 million of net proceeds from the sale of common stock plus net borrowings of \$46.0 million from our predecessor credit facility.

### **Credit facility**

#### *Successor Credit Facility*

The administrative agent of our \$191.7 million successor credit facility is KeyBank National Association. The successor credit facility provides for interest rates plus an applicable margin to be determined based on the London Interbank Offered Rate ("LIBOR") or a base rate ("Base Rate"), at the Company's election. LIBOR borrowings bear interest at LIBOR plus 3.00% to 4.00% depending on the utilization level, and the Base Rate borrowings bear interest at the "Reference Rate," as defined in the successor credit facility, plus 2.00% to 3.00%.

Our approved borrowing base under the successor credit facility, which was \$191.7 million as of December 31, 2017, is redetermined semiannually as early as April and October of each year and up to one additional time between such scheduled determinations upon our request or upon the request of the required lenders (defined as lenders holding 66<sup>2</sup>/<sub>3</sub>% of the aggregate commitments). The borrowing base is determined by the value of our oil and gas reserves but also takes into consideration such information as a repayment analysis of the Company's debt and the forecasted financial condition of the Company. The borrowing base is redetermined (i) in the sole discretion of the administrative agent and all of the lenders, (ii) in accordance with their customary internal standards and practices for valuing and redetermining the value of oil and gas properties in connection with reserve based oil and natural gas loan transactions, (iii) in conjunction with the most recent engineering report and other information received by the administrative agent and the lenders relating to our proved reserves and (iv) based upon the estimated value of our proved reserves as determined by the administrative agent and the lenders.

As of December 31, 2017, the Company had nothing outstanding under the successor credit facility and had the ability to borrow up to the borrowing base of \$191.7 million.

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

The applicable margin varies on a daily basis based on the percentage outstanding under the borrowing base. We incur quarterly commitment fees based on the unused amount of the borrowing base of 0.50% per annum. We may prepay loans under the successor credit facility at any time without premium or penalty (other than customary LIBOR breakage costs).

The successor credit facility contains various covenants limiting our ability to:

- grant or assume liens;
- incur or assume indebtedness;
- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make certain distributions;

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- make certain loans, advances and investments;
- materially change the character of our business as an oil and gas exploration and production company
- engage in transactions with affiliates;
- purchase or carry any margin stock;
- enter into sale and leaseback, take-or-pay or hydrocarbon prepayment transactions; or
- enter into certain swap agreements.

The successor credit facility also contains covenants requiring us to maintain:

- a leverage ratio (*i.e.*, the ratio of consolidated indebtedness, excluding indebtedness under surety bonds, performance bonds or hedge contracts, to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense and other non-cash charges (“EBITDAX”)) not to exceed 3.50 to 1.00.
- an interest coverage ratio (*i.e.*, the ratio of the trailing twelve-month EBITDAX to trailing twelve-month interest expense) of not less than 2.50 to 1.00.
- a current ratio (*i.e.*, the ratio of current assets to current liabilities, excluding unsettled derivatives and the current portion of long-term debt) of not less than 1.0 to 1.0 (current assets include, as of the date of calculation, the aggregate of all lenders’ unused commitment amounts);

The successor credit facility contains customary events of default, including:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- the failure of any representation or warranty to be materially true and correct when made;
- failure to observe any agreement, obligation or covenant in the credit agreement, subject to cure periods for certain failures;
- a cross-default for the payment of any other indebtedness of at least \$5 million;
- bankruptcy or insolvency;
- judgments against us or our subsidiaries, in excess of \$5 million, that are not stayed;
- certain ERISA events involving us or our subsidiaries; and
- a change in control (as defined in the successor credit facility), including the ownership by a “person” or “group” (as defined under the Securities and Exchange Act of 1934, as amended, but excluding certain permitted stockholders) directly or indirectly, of more than 35% of our common stock, other than certain of our current stockholders.

As of December 31, 2017, and through the filing date of this report, the Company is in compliance with all of the successor credit facility covenants.

## **Contractual Obligations**

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We have the following contractual obligations and commitments as of December 31, 2017:

Contractual Obligation	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
	(in thousands)				
Delivery commitments <sup>(1)</sup>	154,541	15,692	50,125	58,276	30,448
Office lease	5,300	1,078	2,559	1,663	—
Asset retirement obligations <sup>(2)</sup>	101,454	2,999	16,427	4,060	77,968
Total	<u>\$ 261,295</u>	<u>\$ 19,769</u>	<u>\$ 69,111</u>	<u>\$ 63,999</u>	<u>\$ 108,416</u>

- (1) The Company has one purchase and transportation agreement and one operating lease. Please refer to *Note 8 - Commitments and Contingencies* for additional discussion on these agreements and for a description of our operating lease.
- (2) 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, 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 see *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. See *Note 1 - Summary of Significant Accounting Policies* to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

#### *Method of accounting for oil and natural gas properties*

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

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

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

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at

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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 in our consolidated financial statements. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

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

### *Oil and natural gas reserve quantities and Standardized Measure*

In the current year, our third-party petroleum consultant prepared our estimates of oil and natural gas reserves and associated future net revenues. In the two years prior, our internal corporate reservoir engineering group prepared, and our third-party petroleum 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 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*

Revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment.

Subsequently, these revenue deductions are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations.

### *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.

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### *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.

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 consolidated statements of operations and comprehensive income.

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

### *Derivatives*

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

### *Stock-based compensation*

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



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

### *Income taxes*

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

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

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. We did not have any uncertain tax positions as of the year ended December 31, 2017.

### *Recent accounting pronouncements*

In May 2014, the FASB issued *Update No. 2014-09, Revenue from Contracts with Customers (Topic 606)* for the recognition of revenue from contracts with customers. Several additional related updates have been 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 Company has assessed substantially all of its revenue contracts and based upon assessments performed to date, we do not expect any significant impact on the timing of revenue recognition or our financial position. The impact of any potential presentation changes will not impact our net income. The Company is currently in the process of finalizing documentation including the assessment of gross-versus-net presentation. The standard is 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 using the modified retrospective approach. We do not currently anticipate any adjustment to our retained earnings upon adoption.

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 do not believe adoption will have a material impact on our financial statements and disclosures.

In February 2016, the FASB issued *Update No. 2016-02 – Leases* to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This authoritative guidance is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years. The Company has begun the identification process of all leases and is evaluating the provisions of this guidance and assessing its impact.

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Effective January 1, 2017, the Company adopted Financial Accounting Standards Board (“FASB”) *Accounting Standards Update (“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 Company's 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 do not believe adoption will have a material impact on our 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 statement 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 do not believe adoption will have a material impact on our statements of cash flows and related disclosures.

In January 2017, the FASB issued *Update 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 do not believe adoption will have a material impact on our financial statements and disclosures.

In May 2017, the FASB issued *Update No. 2017-09 (ASU 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, whereas 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 will be effective for annual or any interim periods beginning after December 15, 2017. We adopted the new standard on the effective date of January 1, 2018 and do not believe adoption will have a material impact on our financial statements and 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, 2017, and through the filing date of this report.

### **Effects of Inflation and Pricing**

Inflation in the United States decreased to 1.8% in 2017 from 2.2% in 2016 and from 2.0% in 2015, which did not have a material impact on our results of operations for the periods ended December 31, 2017, 2016 and 2015. 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% then our proved reserve volumes would decrease by 2% and our PV-10 value as of December 31, 2017 would decrease by approximately 28% or \$169.0 million. The PV-10 value of our Rocky Mountain region, primarily our Wattenberg assets, would decrease by 31% or \$148.3 million.

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

#### *Commodity Derivative Contracts*

Our primary commodity risk management objective is to reduce volatility in our cash flows. We enter into derivative contracts for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only well-capitalized counterparties which have been approved by our board of directors.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in derivative contracts, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices.

Presently, all of our derivative arrangements are concentrated with four counterparties, all of which are lenders under our successor 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.

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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, 2017, a hypothetical upward or downward shift of 10% per Bbl or MMBtu in the NYMEX forward curve as of December 31, 2017 would change our derivative loss by \$14.3 million and \$(13.4) million, respectively.

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

### *Interest Rates*

At December 31, 2017 and on the filing date of this report we had nothing and \$15.0 million outstanding under our successor credit facility, respectively. Borrowings under our successor 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, 2017 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 successor 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 from the Mid-Continent and Rocky Mountain regions depends in part upon the availability, proximity and capacity of third-party refineries, access to regional trucking, pipeline and rail infrastructure, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services, pipelines and rail facilities that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

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

Currently, there are no pipeline systems that service wells in the North Park Basin or French Lake. 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 the North Park Basin or 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 sheet of Bonanza Creek Energy, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2017 (Successor), and the related consolidated statements of operations and comprehensive income (loss), stockholders’ equity, and cash flows 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, 2017 (Successor), and the results of its operations and its cash flows 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, 2017, 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 March 14, 2018 expressed an unqualified opinion.

**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 audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

/s/ GRANT THORNTON LLP

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

Oklahoma City, Oklahoma  
March 14, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

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

We have audited the accompanying consolidated balance sheet of Bonanza Creek Energy, Inc. and subsidiaries as of December 31, 2016, and the related consolidated statements of operations and comprehensive loss, stockholders' equity and cash flows for each of the two years in the period 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 audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Bonanza Creek Energy, Inc. and subsidiaries as of December 31, 2016, and the results of their operations and their cash flows for each of the two years in the period 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, 2017	Predecessor As of December 31, 2016
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$ 12,711	\$ 80,565
Accounts receivable:		
Oil and gas sales	28,549	14,479
Joint interest and other	3,831	6,784
Prepaid expenses and other	6,555	5,915
Inventory of oilfield equipment	1,019	4,685
Derivative asset	488	—
Total current assets	53,153	112,428
Property and equipment (successful efforts method):		
Proved properties	555,341	2,525,587
Less: accumulated depreciation, depletion and amortization	(17,032)	(1,694,483)
Total proved properties, net	538,309	831,104
Unproved properties	183,843	163,369
Wells in progress	47,224	18,250
Other property and equipment, net of accumulated depreciation of \$2,224 in 2017 and \$11,206 in 2016	4,706	6,245
Total property and equipment, net	774,082	1,018,968
Long-term derivative asset	6	—
Other noncurrent assets	3,130	3,082
Total assets	\$ 830,371	\$ 1,134,478
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
Current liabilities:		
Accounts payable and accrued expenses (note 6)	\$ 62,129	\$ 61,328
Oil and gas revenue distribution payable	15,667	23,773
Derivative liability	11,423	—
Predecessor credit facility - current portion (note 7)	—	191,667
Senior Notes - current portion (note 7)	—	793,698
Total current liabilities	89,219	1,070,466
Long-term liabilities:		
Ad valorem taxes	11,584	14,118
Long-term derivative liability	2,972	—
Asset retirement obligations for oil and gas properties	38,262	30,833
Total liabilities	142,037	1,115,417
Commitments and contingencies (note 8)		
Stockholders' equity:		
Predecessor preferred stock, \$.001 par value, 25,000,000 shares authorized, none outstanding as of December 31, 2016	—	—
Predecessor common stock, \$.001 par value, 225,000,000 shares authorized, 49,660,683 issued and outstanding as of December 31, 2016	—	49
Successor preferred stock, \$.01 par value, 25,000,000 shares authorized, none outstanding as of December 31, 2017	—	—
Successor common stock, \$.01 par value, 225,000,000 shares authorized, 20,453,549 issued and outstanding as of December 31, 2017	4,286	—
Additional paid-in capital	689,068	814,990
Retained deficit	(5,020)	(795,978)
Total stockholders' equity	688,334	19,061
Total liabilities and stockholders' equity	\$ 830,371	\$ 1,134,478

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





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

	Successor	Predecessor		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	For the Year Ended December 31, 2016	For the Year Ended December 31, 2015
Operating net revenues:				
Oil and gas sales	\$ 123,535	\$ 68,589	\$ 195,295	\$ 292,679
Operating expenses:				
Lease operating expense	25,862	13,128	43,671	65,038
Gas plant and midstream operating expense	8,341	3,541	12,826	11,368
Severance and ad valorem taxes	9,590	5,671	15,304	18,629
Exploration	3,745	3,699	946	15,827
Depreciation, depletion and amortization	21,312	28,065	111,215	244,921
Impairment of oil and gas properties	—	—	10,000	740,478
Abandonment and impairment of unproved properties	—	—	24,692	33,543
Unused commitments	—	993	7,686	—
Contract settlement expense (note 8)	—	—	21,000	—
General and administrative expense (including \$11,630, \$2,116, \$8,892, and \$14,552, respectively, of stock-based compensation)	42,676	15,092	77,065	70,319
Total operating expenses	111,526	70,189	324,405	1,200,123
Income (loss) from operations	12,009	(1,600)	(129,110)	(907,444)
Other income (expense):				
Derivative gain (loss)	(15,365)	—	(11,234)	56,558
Interest expense	(773)	(5,656)	(62,058)	(57,052)
Reorganization items, net (note 3)	—	8,808	—	—
Gain on termination fee	—	—	6,000	—
Other income (loss)	(1,267)	1,108	(2,548)	(2,503)
Total other income (expense)	(17,405)	4,260	(69,840)	(2,997)
Income (loss) from operations before taxes	(5,396)	2,660	(198,950)	(910,441)
Current income tax benefit (expense) (note 10)	376	—	—	(773)
Deferred income tax benefit (note 10)	—	—	—	165,667
Net income (loss)	\$ (5,020)	\$ 2,660	\$ (198,950)	\$ (745,547)
Comprehensive income (loss)	\$ (5,020)	\$ 2,660	\$ (198,950)	\$ (745,547)
Basic net income (loss) per common share:	\$ (0.25)	\$ 0.05	\$ (4.04)	\$ (15.57)
Diluted net income (loss) per common share:	\$ (0.25)	\$ 0.05	\$ (4.04)	\$ (15.57)
Basic weighted-average common shares outstanding	20,427	49,559	49,268	47,874
Diluted weighted-average common shares outstanding	20,427	50,971	49,268	47,874

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 Capital	Accumulated Earnings (Deficit)	Total
	Shares	Amount			
(in thousands, except share data)					
<b>Balances, January 1, 2015 (Predecessor)</b>	41,287,270	\$ 41	\$ 591,511	\$ 148,519	\$ 740,071
Restricted common stock issued	601,282	1	—	—	1
Restricted common stock forfeited	(123,574)	(1)	—	—	(1)
Restricted stock used for tax withholdings	(108,070)	—	(2,683)	—	(2,683)
Issuance of common stock	47,500	—	326	—	326
Sale of common stock	8,050,000	8	202,680	—	202,688
Stock-based compensation	—	—	14,552	—	14,552
Net loss	—	—	—	(745,547)	(745,547)
<b>Balances, December 31, 2015 (Predecessor)</b>	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)
<b>Balances, December 31, 2016 (Predecessor)</b>	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
<b>Balances, April 28, 2017 (Predecessor)</b>	50,105,217	\$ 49	\$ 793,269	\$ (793,318)	\$ —
Cancellation of Predecessor equity	(50,105,217)	(49)	(793,269)	793,318	—
<b>Balances, April 28, 2017 (Predecessor)</b>	—	\$ —	\$ —	\$ —	\$ —
Issuance of Successor equity	20,356,071	4,285	679,836	—	684,121
<b>Balances, April 28, 2017 (Successor)</b>	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)
<b>Balances, December 31, 2017 (Successor)</b>	20,453,549	\$ 4,286	\$ 689,068	\$ (5,020)	\$ 688,334

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		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
<b>Cash flows from operating activities:</b>				
Net income (loss)	\$ (5,020)	\$ 2,660	\$ (198,950)	\$ (745,547)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:				
Depreciation, depletion and amortization	21,312	28,065	111,215	244,921
Non-cash reorganization items	—	(44,160)	—	—
Deferred income tax (benefit)	—	—	—	(165,667)
Impairment of oil and gas properties	—	—	10,000	740,478
Abandonment and impairment of unproved properties	—	—	24,692	33,543
Well abandonment costs and dry hole expense	75	2,931	872	5,630
Stock-based compensation	11,630	2,116	8,892	14,552
Amortization of deferred financing costs and debt premium	—	374	3,180	2,280
Accretion of contractual obligation for land acquisition	—	—	—	814
Derivative (gain) loss	15,365	—	11,234	(56,558)
Derivative cash settlements	(1,464)	—	18,333	130,996
Inventory write-offs	1,758	—	4,390	—
Other	11	18	(323)	1,429
<b>Changes in current assets and liabilities:</b>				
Accounts receivable	(4,477)	(6,640)	35,282	35,230
Prepaid expenses and other assets	(1,979)	963	(1,838)	8,444
Accounts payable and accrued liabilities	(8,470)	(5,880)	(11,616)	(23,655)
Settlement of asset retirement obligations	(1,167)	(331)	(800)	(867)
Net cash provided by (used in) operating activities	27,574	(19,884)	14,563	226,023
<b>Cash flows from investing activities:</b>				
Acquisition of oil and gas properties	(5,383)	(445)	(98)	(16,270)
Deposits for acquisitions	—	—	—	1,549
Payments of contractual obligation	—	—	(12,000)	(12,000)
Exploration and development of oil and gas properties	(76,375)	(5,123)	(52,344)	(425,918)
Natural gas plant capital expenditures	—	—	—	(112)
(Increase) decrease in restricted cash	(16)	118	(2,613)	2,987
Additions to property and equipment - non oil and gas	(874)	(454)	(346)	(2,809)
Net cash used in investing activities	(82,648)	(5,904)	(67,401)	(452,573)
<b>Cash flows from financing activities:</b>				
Proceeds from predecessor credit facility	—	—	209,000	137,000
Payments to predecessor credit facility	—	(191,667)	(96,333)	(91,000)
Proceeds from sale of common stock	—	207,500	—	209,308
Offering costs related to sale of common stock	—	—	—	(6,620)
Offering costs related to sale of Senior Notes	—	—	—	(99)
Payment of employee tax withholdings in exchange for the return of common stock	(2,398)	(427)	(289)	(2,683)
Deferred financing costs	—	—	(316)	(599)
Net cash provided by (used in) financing activities	(2,398)	15,406	112,062	245,307
Net change in cash and cash equivalents	(57,472)	(10,382)	59,224	18,757
<b>Cash and cash equivalents:</b>				
Beginning of period	70,183	80,565	21,341	2,584
End of period	\$ 12,711	\$ 70,183	\$ 80,565	\$ 21,341
<b>Supplemental cash flow disclosure:</b>				
Cash paid for interest	\$ 523	\$ 3,509	\$ 58,900	\$ 54,566

Stock issued for litigation settlement

\$	—	\$	—	\$	—	\$	326
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Cash paid for income taxes	\$ —	\$ —	\$ —	\$ 820
Contractual obligation for land acquisition	\$ —	\$ —	\$ —	\$ 12,000
Cash paid for reorganization items	\$ —	\$ 52,968	\$ —	\$ —
Changes in working capital related to exploration, development and acquisition of oil and gas properties	\$ 16,057	\$ 3,360	\$ (30,044)	\$ (50,385)

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, exploiting and producing oil and gas properties. The Company’s assets and operations are concentrated primarily in the Wattenberg Field in Colorado and in the Dorcheat Macedonia Field in southern Arkansas.

*Basis of Presentation*

The consolidated 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. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2017, through the filing date of this report.

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. See *Note 3 - 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. References to “Current Successor Period” relates to the period of April 29, 2017 through December 31, 2017. References to “Current Predecessor Period” relate to the period of January 1, 2017 through April 28, 2017. References to “Prior Predecessor Period” relate to the year ended December 31, 2016.

*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.

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### *Going Concern Presumption*

Our condensed 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. 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.

The Company assesses its unproved properties periodically for impairment on a property-by-property basis, which requires significant judgment. The Company considers the following factors in its assessment of the impairment of unproved properties:

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

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- 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 4 - 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 (“accompanying 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.

### *Natural Gas Plants*

Natural gas plants are recorded at cost and are deemed part of the upstream oil and gas producing activities of the Company as they primarily serve Company wells and have limited viability on their own. The natural gas plants are shown within the proved properties in the accompanying balance sheets. The natural gas plants are depleted on a units-of-production method.

### *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.

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, at which point they were deemed held for sale. As of December 31, 2017, the assets within the Company's Mid-Continent region and North Park Basin represented \$82.7 million, net of accumulated depreciation, depletion and amortization. There is a corresponding asset retirement obligation liability of approximately \$11.0 million related to these assets.

The Company successfully sold its North Park Basin on March 9, 2018 for \$0.1 million and full release of all current and future obligations. As of December 31, 2017, the assets within the Company's North Park Basin represented \$0.3 million, net of accumulated depreciation, depletion and amortization. There is a corresponding asset retirement obligation liability of approximately \$5.4 million related to these assets.

### *Revenue Recognition*

The Company records revenues, net of royalties, discounts, and allowances, as applicable, from the sales of crude oil, natural gas and natural gas liquids (“NGLs”) when delivery to the customer has occurred and title has transferred. This occurs



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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, 2017 and 2016.

For gathering and processing services, the Company either receives fees or commodities from natural gas producers depending on the type of contract. Under the percentage-of-proceeds contract type, the Company is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Commodities received are, in turn, sold and recognized as revenue in accordance with the criteria outlined above.

### *Income Taxes*

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

### *Uncertain Tax Positions*

The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The tax returns for 2016, 2015 and 2014 are still subject to audit by the Internal Revenue Service. There were no uncertain tax positions.

### *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, 2017, 2016 and 2015, NGL Crude Logistics accounted for 44%, 0% and 0%, respectively, Lion Oil Trading & Transportation, Inc. accounted for 18%, 18% and 16%, respectively, Duke Energy Field Services accounted for 16%, 14% and 11%, respectively, Silo Energy Company accounted for 0%, 50% and 31%, respectively, and Plains Marketing LP accounted for 0%, 0% and 11%, respectively, of our oil and natural gas 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 or collars. The oil contracts are indexed to NYMEX WTI prices, and natural gas contracts are indexed to NYMEX HH prices, which have a high degree of historical correlation with actual prices received by the Company, 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 (loss) per common share is calculated by dividing net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested RSUs, in-the-money outstanding stock options 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

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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, predecessor and successor credit facilities, senior notes, and derivative instruments. Cash and cash equivalents, trade receivables, trade payables and accrued liabilities are carried at cost and approximate fair value due to the short-term nature of these instruments. Our successor and predecessor credit facilities have variable interest rates so they approximate fair value. Our senior notes were recorded at cost, and their fair value is disclosed within *Note 12 - Fair Value Measurements*. Derivative instruments are recorded at fair value. The book value of our previous contractual obligation for land acquisition approximates fair value due to it being discounted at a market-based interest rate.

### *Recently Issued and Adopted Accounting Standards*

In May 2014, the FASB issued *Update No. 2014-09, Revenue from Contracts with Customers (Topic 606)* for the recognition of revenue from contracts with customers. Several additional related updates have been 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 Company has assessed substantially all of its revenue contracts and based upon assessments performed to date, we do not expect any significant impact on the timing of revenue recognition or our financial position. The impact of any potential presentation changes will not impact our net income. The Company is currently in the process of finalizing documentation including the assessment of gross-versus-net presentation. The standard is 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 using the modified retrospective approach. We do not currently anticipate any adjustment to our retained earnings upon adoption.

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 do not believe adoption will have a material impact on our financial statements and disclosures.

In February 2016, the FASB issued *Update No. 2016-02 – Leases* to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This authoritative guidance is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years. The Company has begun the identification process of all leases and is evaluating the provisions of this guidance and assessing its impact.

Effective January 1, 2017, the Company adopted Financial Accounting Standards Board ("FASB") *Accounting Standards Update ("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

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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 Company's 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 do not believe adoption will have a material impact on our 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 statement 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 do not believe adoption will have a material impact on our statements of cash flows and related disclosures.

In January 2017, the FASB issued *Update 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 do not believe adoption will have a material impact on our financial statements and disclosures.

In May 2017, the FASB issued *Update No. 2017-09 (ASU 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, whereas 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 will be effective for annual or any interim periods beginning after December 15, 2017. We adopted the new standard on the effective date of January 1, 2018 and do not believe adoption will have a material impact on our financial statements and 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, 2017, and through the filing date of this report.

### **NOTE 2 - 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").

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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.

### *Plan of 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"), each of which will be distributed as set forth below;

- 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% is 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.

### *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, and is actively conducting a search for a new Chief Executive Officer.

### **NOTE 3 - FRESH-START ACCOUNTING**

Upon the Company's emergence from Chapter 11 bankruptcy, the Company adopted fresh-start accounting, pursuant to FASB *Accounting Standards Codification* ("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.

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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	\$	<u>680,040</u>
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	\$	<u>794,972</u>

**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)				
<b>ASSETS</b>				
<b>Current Assets:</b>				
Cash and cash equivalents	\$ 96,286	\$ (26,103) <sup>(1)</sup>	\$ —	\$ 70,183
Accounts receivable:				
Oil and gas sales	24,876	—	—	24,876
Joint interest and other	3,028	—	—	3,028

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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) <sup>(6)</sup>	500,461
Less: accumulated depreciation, depletion and amortization	(1,720,736)	—	1,720,736 <sup>(6)</sup>	—
Total proved properties, net	811,098	—	(310,637)	500,461
Unproved properties	163,781	—	14,679 <sup>(6)</sup>	178,460
Wells in progress	18,002	—	(18,002) <sup>(7)</sup>	—
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) <sup>(2)</sup>	\$ —	\$ 38,934
Oil and gas revenue distribution payable	24,937	—	—	24,937
Predecessor credit facility - current portion	191,667	(191,667) <sup>(3)</sup>	—	—
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) <sup>(8)</sup>	29,061
Liabilities subject to compromise	873,292	(873,292) <sup>(4)</sup>	—	—
Total liabilities	\$ 1,212,110	\$ (1,098,660)	\$ (2,599)	\$ 110,851
Stockholders' equity:				
Predecessor preferred stock	—	—	—	—
Predecessor common stock	49	—	(49) <sup>(9)</sup>	—
Additional paid in capital	816,679	—	(816,679) <sup>(9)</sup>	—
Successor common stock	—	204 <sup>(5)</sup>	—	204
Successor warrants	—	4,081 <sup>(5)</sup>	—	4,081
Additional paid-in capital	—	679,836 <sup>(5)</sup>	—	679,836
Retained deficit	(893,803)	388,436 <sup>(4)</sup>	505,367 <sup>(10)</sup>	—
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):

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Sources:

Proceeds from rights offering	\$	200,000
Proceeds from ad hoc equity committee		7,500
Total sources	\$	<u>207,500</u>

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	\$	<u>(233,603)</u>
Total net sources, uses and transfers	\$	<u>(26,103)</u>

(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	\$	<u>(33,701)</u>

(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		<u>873,292</u>
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	\$	<u>411,845</u>
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	\$	<u>388,436</u>

(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 4 - IMPAIRMENTS**

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 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*.

For the year ended December 31, 2015, the Company impaired its assets held for sale within the Mid-Continent region to their fair value resulting in proved property impairments of \$321.2 million and \$419.3 million of proved property impairments in the Rocky Mountain region due to low commodity prices. The Company incurred unproved properties impairments of \$24.8 million for non-core lease expirations in the Wattenberg Field and \$8.7 million of impairment charges to fully impair the North Park Basin due to a change in the Company's development plan during the year.

**NOTE 5 - OTHER NONCURRENT ASSETS**

The Company had unamortized deferred financing costs related to its predecessor credit facility, which were classified as other noncurrent assets in the accompanying balance sheet as of December 31, 2016. In accordance with authoritative guidance, the deferred financing costs related to the Company's Senior Notes were presented as a reduction of the Senior Notes on the accompanying balance sheet as of December 31, 2016 and are not included below (in thousands).

	Successor		Predecessor	
	As of December 31, 2017		As of December 31, 2016	
Restricted cash	\$	2,754	\$	2,855
Deferred financing costs - predecessor credit facility		—		227
AMT credit refund		376		—
Other noncurrent assets	\$	3,130	\$	3,082

**NOTE 6 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES**

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

	Successor	Predecessor
	As of December 31, 2017	As of December 31, 2016
Drilling and completion costs	\$ 21,833	\$ 2,415
Accounts payable trade	6,256	1,140
Accrued general and administrative cost	10,025	17,539
Lease operating expense	5,005	2,895
Accrued interest	250	14,209
Silo contract settlement accrual	—	7,228
Accrued oil and gas hedging	808	—
Production and ad valorem taxes and other	17,952	15,902
<b>Total accounts payable and accrued expenses</b>	<b>\$ 62,129</b>	<b>\$ 61,328</b>

**NOTE 7 - LONG-TERM DEBT**

The Company filing for Chapter 11 constituted an event of default with respect to its existing debt obligations. As a result, the Company's Senior Notes and predecessor credit facility became immediately due and payable, but any efforts to enforce such payment obligations were automatically stayed as a result of the Chapter 11 filing. On April 28, 2017, upon the Company's emergence from bankruptcy, the Senior Notes were exchanged for new common stock of the reorganized entity. Please refer to *Note 2 - Chapter 11 Proceedings and Emergence* for additional discussion.

Long-term debt consisted of the following as of December 31, 2017 and 2016 (in thousands):

	Successor	Predecessor
	As of December 31, 2017	As of December 31, 2016
Successor credit facility	\$ —	\$ —
Predecessor credit facility	—	\$ 191,667
6.75% Senior Notes due 2021	—	500,000
Unamortized premium on 6.75% Senior Notes	—	5,165
5.75% Senior Notes due 2023	—	300,000
Less debt issuance costs - Senior Notes	—	(11,467)
<b>Total debt, net</b>	<b>—</b>	<b>985,365</b>
Less current portion <sup>(1)</sup>	—	(985,365)
<b>Total long-term debt</b>	<b>\$ —</b>	<b>\$ —</b>

(1) Due to covenant violations in 2016, the Company classified the Senior Notes as current liabilities.

**Successor Debt**

*Successor 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 "successor credit facility"). The new borrowing base of \$191.7 million is redetermined semiannually, as early as April and October of each year, with the first redetermination set to occur in April of 2018. The successor credit facility matures on March 31, 2021. As of the date of filing, the Company had \$15.0 million outstanding under the successor credit facility.

The successor credit facility restricts, among other items, certain dividend payments, additional indebtedness, purchase of margin stock, asset sales, loans, investments and mergers. The successor credit facility also contains certain

financial covenants, which require the maintenance of certain financial and leverage ratios, as defined by the successor credit facility. The successor credit facility states that beginning with the fiscal quarter ending September 30, 2017, and each following fiscal quarter through the maturity of the successor credit facility, the Company's leverage ratio of indebtedness to EBITDAX is 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 must 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 successor credit facility also requires 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 is 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 successor credit facility covenants.

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

The successor credit facility provides for interest rates plus an applicable margin to be determined based on LIBOR or a base rate, at the Company's election. LIBOR borrowings bear interest at LIBOR, plus a margin of 3.00% to 4.00% depending on the utilization level, and the base rate borrowings bear interest at the "Reference Rate," as defined in the successor credit facility, plus a margin of 2.00% to 3.00% depending on the utilization level.

## **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 applicable lenders under the predecessor credit facility deemed the Company in default due to a covenant violation on November 14, 2016 causing the then outstanding balance under the predecessor credit facility to bear interest at the Bank Prime Rate plus the applicable utilization margin and 2% penalty fee.

The borrowing base on the predecessor credit facility was reduced on May 20, 2016 from \$475.0 million to \$200.0 million, and was further reduced from \$200.0 million to \$150.0 million on October 31, 2016. The borrowing base was redetermined semiannually, as early as April and October of each year. The predecessor credit facility was collateralized by substantially all of the Company's assets and matured on September 15, 2017. 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 to be paid back in five remaining monthly installments of \$8.3 million, with no additional available borrowing capacity. The Company filed for bankruptcy under Chapter 11 of the Bankruptcy Code on January 4, 2017, granting the Company a stay from making any further deficiency payments. During the bankruptcy proceedings, the Company paid interest on the predecessor credit facility in the normal course. On the Effective Date, the predecessor credit facility was terminated and the outstanding principal balance of \$191.7 million, accrued interest of \$1.1 million, and fees of \$0.9 million were paid in full. The obligations were funded with proceeds from the rights offering.

### *Senior Unsecured Notes*

The \$500.0 million aggregate principal amount of 6.75% Senior Notes that mature on April 15, 2021 and the \$300.0 million aggregate principal amount of 5.75% Senior Notes that mature on February 1, 2023 were unsecured senior obligations.

The Senior Notes were included in liabilities subject to compromise on the condensed consolidated balance sheets of the Predecessor Company as of April 28, 2017, as presented in *Note 3 - Fresh-Start Accounting*, and in current liabilities as of December 31, 2016 within the accompanying balance sheets. 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 was issued.

Please refer to *Note 2 - Chapter 11 Proceedings and Emergence* and *Note 3 - Fresh-Start Accounting* for additional discussion about the Company's emergence from bankruptcy.

## 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.

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 has 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 in excess of \$100,000 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 \$0.7 million in 2017 and currently anticipates spending \$3.5 million in 2018, and \$3.1 million for 2019 through 2022. The COC can be terminated after four years with a showing of substantial compliance and CDPHE approval.

### *Commitments*

Upon emergence from bankruptcy, the new purchase agreement to deliver fixed determinable quantities of crude oil with NGL (the "new NGL agreement") 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 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 are no minimum volume commitments for the year ending December 31, 2017. During 2018, the average minimum volume commitment will be 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 \$154.5 million as of December 31, 2017. 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.

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In October 2014, the Company entered into a purchase agreements to deliver fixed determinable quantities of crude oil to Silo. This agreement went into effect during the second quarter of 2015 for 12,580 barrels per day over an initial five-year term. While the volume commitment could be met with Company volumes or third-party volumes, delegated by the Company, the Company was required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. As confirmed in the Plan, the Company terminated its purchase agreement with Silo on February 1, 2017, and entered into a settlement agreement pursuant to which Silo received \$21.0 million. Specifically, the settlement 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.

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.

The annual minimum commitment payments on the new NGL agreement and the new office lease for the next five years as of December 31, 2017 are presented below (in thousands):

	NGL Commitments <sup>(1)</sup>	Office Lease Commitments	Total
2018	\$ 15,692	1,078	16,770
2019	22,176	1,224	23,400
2020	27,949	1,335	29,284
2021	28,791	1,423	30,214
2022	29,485	240	29,725
2023 and thereafter	30,448	—	30,448
Total	\$ 154,541	5,300	159,841

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

## NOTE 9 - STOCK-BASED COMPENSATION

### 2017 Long Term Incentive Plan

Upon emergence from bankruptcy, and approved by the court and the prior board, the Company adopted a new Long Term Incentive Plan (the "2017 LTIP") and issued new grants to employees consisting of options with a ten-year term and strike price of \$34.36 and restricted stock units. These awards vest over a three-year period in equal installments each year from the grant date. See below for further discussion of awards under the 2017 LTIP.

#### *Restricted Stock Units*

The 2017 LTIP allows for the issuance of restricted stock units ("RSU") to non-executive members of the board of directors and employees 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 on-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.

The Company granted 389,102 RSUs with a fair value \$13.4 million during the Current Successor Period. Total expense recorded for RSUs, inclusive of the board of director grants, for the Current Successor Period was \$7.9 million. As of December 31, 2017, unrecognized compensation cost was \$7.1 million and will be amortized through 2020.

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

	Restricted Stock Units	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of Current Successor Period	—	\$ —
Granted	452,996	\$ 34.62
Vested	(173,200)	\$ 34.19
Forfeited	(18,631)	\$ 34.36
Non-vested as of December 31, 2017	<u>261,165</u>	<u>\$ 34.93</u>

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 Successor Period ended December 31, 2017.

*Stock Options*

The 2017 LTIP allows 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.

The Company granted 389,102 stock options with a fair value \$6.8 million during the Current Successor Period. Total expense recorded for stock options for the Current Successor Period was \$3.7 million. As of December 31, 2017, unrecognized compensation cost was \$2.7 million and will be amortized through 2020.

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

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 for the Current Successor Period 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	6	\$ —
Outstanding as of December 31, 2017	<u>197,271</u>	<u>\$ 34.36</u>	<u>6</u>	<u>\$ —</u>

There were no options outstanding and exercisable as of December 31, 2017.

**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 represents 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 Current Predecessor Period or 2016. 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, \$6.1 million and \$11.1 million for the Current Predecessor Period and the years ended December 31, 2016 and 2015, respectively.

There were no shares of restricted stock granted to non-employee directors under the Predecessor Plan during the Current Predecessor Period. During the years ended December 31, 2016 and 2015, the Company issued 113,044 and 32,450 shares, respectively, of restricted common stock under the Predecessor Plan to its non-employee directors. The Company recognized compensation expense of \$0.04 million, \$0.7 million and \$0.7 million for the Current Predecessor Period and the years ended December 31, 2016 and 2015, respectively. These awards vested approximately one year after issuance.

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

	<b>Predecessor</b>					
	<b>January 1, 2017 through April 28, 2017</b>		<b>For the Year Ended December 31, 2016</b>		<b>For the Year Ended December 31, 2015</b>	
	<b>Restricted Stock</b>	<b>Weighted-Average Grant-Date Fair Value</b>	<b>Restricted Stock</b>	<b>Weighted-Average Grant-Date Fair Value</b>	<b>Restricted Stock</b>	<b>Weighted-Average Grant-Date Fair Value</b>
Non-vested at beginning of year	368,887	\$ 19.45	731,818	\$ 29.47	589,529	\$ 37.66
Granted	—	\$ —	113,044	\$ 0.98	601,282	\$ 24.04
Vested	(111,996)	\$ 32.22	(355,498)	\$ 31.68	(335,419)	\$ 32.09
Forfeited	(5,134)	\$ 29.55	(120,477)	\$ 27.34	(123,574)	\$ 34.86
Canceled	(251,757)	\$ 13.08	—	\$ —	—	\$ —
Non-vested at end of period	<u>—</u>	<u>\$ —</u>	<u>368,887</u>	<u>\$ 19.45</u>	<u>731,818</u>	<u>\$ 29.47</u>

The Company recorded no excess tax benefits for the Current Predecessor Period or the years ended December 31, 2016 and 2015.

*Performance Stock Units under the Predecessor Long Term Incentive Plan*

The Company granted performance stock units (“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 is 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 criterion for the PSUs is based on a comparison of the Company’s total shareholder return (“TSR”) for the measurement period compared with the TSRs of a group of peer companies for the same measurement period. Compensation expense associated with PSUs was recognized as general and

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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 following table presents the assumptions used to determine the fair value of the PSUs granted during the year ended December 31, 2015 (Predecessor).

	<b>For the Year Ended December 31, 2015</b>
Expected term of award	3
Risk-free interest rate	0.15% - 0.99%
Expected volatility	65%

The Company granted no PSUs under the Predecessor Plan during the Current Predecessor Period or 2016. During 2015, the Company granted 144,363 PSUs under the Predecessor Plan to certain officers. The fair value of the PSUs granted in 2015 was \$4.8 million. The Company recognized compensation expense of \$0.5 million, \$1.8 million and \$2.8 million for the Current Predecessor Period and the years ended December 31, 2016 and 2015, respectively.

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

	<b>Predecessor</b>					
	<b>January 1, 2017 through April 28, 2017</b>		<b>For the Year Ended December 31, 2016</b>		<b>For the Year Ended December 31, 2015</b>	
	<b>PSU</b>	<b>Weighted- Average Grant-Date Fair Value</b>	<b>PSU</b>	<b>Weighted- Average Grant-Date Fair Value</b>	<b>PSU</b>	<b>Weighted- Average Grant-Date Fair Value</b>
Non-vested at beginning of year <sup>(1)</sup>	21,538	\$ 33.31	114,833	\$ 35.27	94,173	\$ 37.55
Granted <sup>(1)</sup>	—	\$ —	—	\$ —	144,363	\$ 33.44
Vested <sup>(1)</sup>	—	\$ —	(59,725)	\$ 36.61	(107,053)	\$ 34.84
Forfeited <sup>(1)</sup>	—	\$ —	(33,570)	\$ 35.55	(16,650)	\$ 37.00
Canceled <sup>(1)</sup>	(21,538)	\$ 33.31	—	\$ —	—	\$ —
Non-vested at end of period <sup>(1)</sup>	—	\$ —	21,538	\$ 33.31	114,833	\$ 35.27

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

During the Current 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. During the year ended December 31, 2015, the first tranche of the 2015 awards, the second tranche



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of the 2014 awards and the 2013 awards had a zero-times multiplier, 1.00-times multiplier and 0.91-times multiplier, respectively, 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 Current Predecessor Period. During the year end December 31, 2016, the Company granted 2,958,558 of units for a total fair value \$2.9 million, that settled in shares of the Company’s common stock upon vesting. The units vest in one-third increments over three years. The units contain 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 Current Predecessor period and the year ended December 31, 2016 was \$0.4 million and \$0.9 million, respectively.

A summary of the status and activity of non-vested units for the Current Predecessor Period and the year ended December 31, 2016 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	<u>—</u>	<u>\$ —</u>	<u>2,443,402</u>	<u>\$ 0.99</u>

#### **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 \$0.6 million, \$0.6 million, \$2.0 million, and \$1.9 million for the Current Successor period, Current Predecessor period and the years ended December 31, 2016 and 2015, respectively.

#### **NOTE 10 - INCOME TAXES**

On December 22, 2017 the U.S. Government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”). The Tax Act makes broad and complex changes to the U.S. tax code that will affect 2017, including but not limited to, (1) bonus depreciation that will allow for full (100%) expensing of qualified property acquired and placed into service after September 27, 2017, and (2) limitations on the deductibility of certain executive compensation under IRC §162(m) related to plans made after November 2, 2017.

The Tax Act also establishes new tax laws that will affect 2018, including but not limited to, (1) reduction of U.S. federal corporate tax rate to 21%; (2) the elimination of the corporate alternative minimum tax (“AMT”) and refunding of existing AMT credit carryforwards; (3) limitation on deductible interest expense; (4) the repeal of the domestic production activity deduction (DPAD); and (5) limitations on net operating losses (“NOL’s”) generated after December 31, 2017 to 80% of taxable income. The NOL’s generated in 2018 and beyond are to be carried forward indefinitely with no carryback.

The Tax Act preserved the deductibility of intangible drilling costs for federal income tax purposes, which allows us to deduct all or a portion of intangible drilling costs in the year incurred and minimizes current taxes payable in periods of taxable income.

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Deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of enacted tax laws. On December 22, 2017, the Tax Act was enacted, which reduced the federal corporate tax rate from 35% to 21% beginning January 1, 2018. We recognized the effect of this rate change on our deferred tax assets and liabilities in 2017, which resulted in a noncash decrease to the income tax provision of \$74.0 million, which was subject to a valuation allowance at December 31, 2017. Tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. In addition, the Tax Act provides for a refund of previous AMT credits, and we accordingly reversed the valuation allowance on our AMT credit carryforward of \$0.4 million that will now be refundable through 2021 and have reclassified this amount from deferred tax asset to other noncurrent assets on the accompanying balance sheets.

We will continue to analyze the Tax Act and future IRS regulations, refine its calculations and gain a more thorough understanding of how individual states are implementing this new law. This further analysis could potentially affect the measurement of deferred tax balances or potentially give rise to new deferred tax amounts.

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

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

	Successor	Predecessor		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Current tax (expense) benefit				
Federal	\$ 376	\$ —	\$ —	\$ 192
State	—	—	—	(965)
Deferred tax (expense) benefit	—	—	—	165,667
Total income tax (expense) benefit	\$ 376	\$ —	\$ —	\$ 164,894

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

	Successor As of December 31, 2017	Predecessor As of December 31, 2016
Deferred tax liabilities:		
Oil and gas properties	\$ —	\$ 4,136
Total deferred tax liabilities	—	4,136
Deferred tax assets:		
Federal and state tax net operating loss carryforward	117,115	234,544
Oil and gas properties	1,319	—
Derivative liability	3,457	—
Reclamation costs	9,516	11,841
Stock compensation	1,419	6,694
Accrued compensation	1,285	2,228
Inventory	1,529	—
Settlement liabilities	—	2,761
AMT credit	—	403
State bonus depreciation addback	1,089	1,481
Other long-term liabilities	231	406
Total deferred tax assets	136,960	260,358
Less: Valuation allowance	136,960	256,222
Total deferred tax assets after valuation allowance	—	4,136
Total non-current net deferred tax liability	\$ —	\$ —

The Company has \$477.6 million and \$618.5 million of net operating loss carryovers for federal income tax purposes, of which \$0.0 million and \$14.4 million is not recorded as a benefit for financial statement purposes as it relates to tax deductions that are different from the stock-based compensation expense recorded for financial statement purposes, as of December 31, 2017 and 2016, respectively. The federal net operating loss carryforward begins to expire in 2031. The benefit of these excess tax deductions will not be recognized for financial statement purposes until the related deductions reduce taxes payable.

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Federal income tax expense differs from the amount that would be provided by applying the statutory United States federal income tax rate of 35% 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		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Federal statutory tax (expense) benefit by applying the statutory rate	\$ 1,889	\$ (931)	\$ 69,633	\$ 318,654
Decrease (increase) in tax resulting from:				
State tax expense net of federal benefit	172	(85)	6,358	30,178
Prior year true-up	—	(7,572)	—	—
Stock compensation	—	(1,773)	—	—
Permanent differences	(715)	(35,273)	—	—
Rate change	(73,956)	—	—	—
Other	(642)	—	(317)	(3,390)
Valuation allowance	73,628	45,634	(75,674)	(180,548)
Total income tax (expense) benefit	\$ 376	\$ —	\$ —	\$ 164,894

During the year ended December 31, 2017, the decrease in tax rate was primarily due to the enactment of the 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. Net operating losses are inherently subject to changes in ownership.

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. Net operating losses are inherently subject to changes in ownership.

During the year ended December 31, 2015, the decrease in tax rate was primarily due to placing a valuation allowance against net deferred tax assets. Total deferred income tax benefit in the accompanying statements of operations is \$165.7 million.

The Company had no unrecognized tax benefits as of December 31, 2017, 2016 and 2015.

**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.

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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 2 - Chapter 11 Proceedings and Emergence* and *Note 3 - 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):

Beginning balance as of January 1, 2016 (Predecessor)	\$	25,688
Additional liabilities incurred		90
Accretion expense		2,601
Liabilities settled		(691)
Revisions to estimate		3,145
Balance as of December 31, 2016 (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)
<hr/>		
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

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 Current 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. Revisions to estimates for the year ended December 31, 2016 were a result of decreased estimated economic well lives coupled with a decrease 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.

**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

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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, 2017 and 2016 and their classification within the fair value hierarchy:

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

  

	Predecessor		
	As of December 31, 2016		
	Level 1	Level 2	Level 3
	(in thousands)		
Unproved properties <sup>(2)</sup>	\$ —	\$ —	\$ 162,682
Asset retirement obligations <sup>(3)</sup>	\$ —	\$ —	\$ 3,145

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

(2) This represents non-financial assets that are measured at fair value on a nonrecurring basis due to impairments. This is the fair value of the asset base that was subjected to impairment and does not reflect the entire asset balance as presented on the accompanying balance sheets. Please refer to the *Unproved Oil and Gas Properties* sections below for additional discussion.

(3) 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

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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 year ended December 31, 2017. The Company impaired its oil and gas properties in the Mid-Continent region which had a carrying value of \$110.0 million to its fair value of \$100.0 million and recognized an impairment of \$10.0 million for the year ended December 31, 2016. For additional discussion on impairments, please refer to Note 4 - 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. There were no unproved oil and gas property impairments during the year ended December 31, 2017. 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 for the year ended December 31, 2016 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 \$8.5 million and \$3.1 million of asset retirement obligations recorded at fair value as of December 31, 2017 and 2016, 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 fair value of the 6.75% Senior Notes and 5.75% Senior Notes as of December 31, 2016 was \$371.9 million and \$222.0 million, respectively. The Senior Notes were measured using Level 1 inputs based on a secondary market trading price. The outstanding balance under the predecessor credit facility as of December 31, 2016 was \$191.7 million, which approximates fair value as the applicable interest rates are floating.

## **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 and collar arrangements for oil and gas and none of the derivative instruments qualify as having hedging relationships.

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

As of December 31, 2017, the Company had entered into the following commodity derivative contracts:

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	Crude Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu
<b>1Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,000	\$53.20	6,000	\$3.36
<b>2Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,000	\$53.20	—	—
<b>3Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	2,000	\$51.96	—	—
<b>4Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	2,000	\$51.96	—	—
<b>1Q19</b>				
Cashless Collar	2,000	\$43.00/\$54.53	2,600	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q219</b>				
Cashless Collar	1,330	\$44.01/\$54.79	857	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q319</b>				
Swap	2,000	\$52.50	—	—
<b>Q419</b>				
Swap	2,000	\$52.50	—	—



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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)	
	Bbls/day	Weighted Avg. Price per Bbl	MMBtu/day	Weighted Avg. Price per MMBtu
<b>1Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,172	\$53.60	6,000	\$3.36
<b>2Q18</b>				
Cashless Collar	2,000	\$42.00/\$52.50	5,600	\$2.75/\$3.43
Swap	3,500	\$54.26	—	—
<b>3Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	3,000	\$54.97	—	—
<b>4Q18</b>				
Cashless Collar	2,000	\$43.00/\$53.50	5,600	\$2.75/\$3.43
Swap	2,000	\$51.96	—	—
<b>1Q19</b>				
Cashless Collar	2,000	\$43.00/\$54.53	2,600	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q219</b>				
Cashless Collar	1,330	\$44.01/\$54.79	857	\$2.75/\$3.40
Swap	1,000	\$53.20	—	—
<b>Q319</b>				
Swap	2,000	\$52.50	—	—
<b>Q419</b>				
Swap	2,000	\$52.50	—	—

*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, 2017 and 2016 (in thousands):

	Balance Sheet Location	Successor	Predecessor
		As of December 31, 2017	As of December 31, 2016
		Fair Value	Fair Value
<i>Derivative Assets:</i>			
Commodity contracts	Current assets	\$ 488	\$ —
Commodity contracts	Noncurrent assets	6	—
<i>Derivative Liabilities:</i>			
Commodity contracts	Current liabilities	(11,423)	—
Commodity contracts	Long-term liabilities	(2,972)	—
Total derivative liabilities, net		\$ (13,901)	\$ —

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

	Successor	Predecessor		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	December 31, 2015 <sup>(1)</sup>
Derivative cash settlement gain (loss):				
Oil contracts	\$ (1,486)	\$ —	\$ 18,333	\$ 128,258
Gas contracts	22	—	—	2,738
Total derivative cash settlement gain (loss) <sup>(2)</sup>	\$ (1,464)	\$ —	\$ 18,333	\$ 130,996
Change in fair value gain (loss)	(13,901)	\$ —	\$ (29,567)	\$ (74,438)
Total derivative gain (loss) <sup>(2)</sup>	\$ (15,365)	\$ —	\$ (11,234)	\$ 56,558

(1) During the year ended December 31, 2015, the Company paid \$10.5 million to convert its three-way collars, that settled during the third and fourth quarters of 2015, to two-way collars.

(2) 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 Successor Company issued restricted stock units which represent the right to receive, upon vesting, one share of the Company's new common stock. The Successor Company issued stock options and warrants, which both represent the right to purchase the Company's new 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, stock options and warrants of the Successor Company are all non-participating securities, and therefore, the Company used the treasury stock method to calculate earnings per share as shown in the following table (in thousands, except per share amounts):

	Successor
	April 29, 2017 through December 31, 2017
Net loss	\$ (5,020)
Basic net loss per common share	\$ (0.25)
Diluted net loss per common share	\$ (0.25)
Weighted-average shares outstanding - basic	20,427
Add: dilutive effect of contingent stock awards	—
Weighted-average shares outstanding - diluted	20,427

The Company was in a net loss position for the Current 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.

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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 Current Predecessor Period and the years ended December 31, 2016 and 2015:

	Predecessor		
	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
	(in thousands, except per share amounts)		
Net income (loss)	\$ 2,660	\$ (198,950)	\$ (745,547)
Less: undistributed income to unvested restricted stock	120	—	—
Undistributed income (loss) to common shareholders	2,540	(198,950)	(745,547)
Basic net income (loss) per common share	\$ 0.05	\$ (4.04)	\$ (15.57)
Diluted net income (loss) per common share	\$ 0.05	\$ (4.04)	\$ (15.57)
Weighted-average shares outstanding - basic	49,559	49,268	47,874
Add: dilutive effect of contingent PSUs	1,412	—	—
Weighted-average shares outstanding - diluted	50,971	49,268	47,874

The Predecessor Company was in a net loss position for the years ended December 31, 2016 and 2015, which made the 519,362 and 277,634, respectively, potentially dilutive shares, anti-dilutive. The Predecessor Company had 258,126 anti-dilutive shares for the Current Predecessor Period. The participating shareholders are not contractually obligated to share in the losses of the Predecessor Company, and therefore, the entire net loss is allocated to the outstanding common shareholders.

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

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

	Successor	Predecessor		
	April 29, 2017 through December 31, 2017	January 1, 2017 through April 28, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Acquisition <sup>(1)</sup>	\$ 5,383	\$ 445	\$ 97	\$ 16,270
Development <sup>(2)(3)</sup>	106,449	10,780	31,209	393,187
Exploration	3,671	769	74	6,284
Total <sup>(4)</sup>	\$ 115,503	\$ 11,994	\$ 31,380	\$ 415,741

(1) Acquisition costs for unproved properties for the Current Successor Period, Current Predecessor Period, and the years ended December 31, 2016 and 2015 were \$5.4 million, \$0.4 million, \$0.1 million and \$15.3 million, respectively. There were no acquisition costs for proved properties for the Current Successor Period, Current Predecessor Period or the year ended December 31, 2016 and \$1.0 million for the year ended December 31, 2015.

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- (2) Development costs include workover costs of \$4.3 million, \$1.8 million, \$6.0 million and \$10.0 million charged to lease operating expense for the Current Successor Period, Current Predecessor Period, and the years ended December 31, 2016 and 2015, respectively.
- (3) Includes amounts relating to asset retirement obligations of \$8.3 million, \$3.1 million and \$2.4 million for the Current Successor Period and the years ended December 31, 2016 and 2015, respectively. There were no asset retirement obligations included in the Current Predecessor Period.

***Suspended Well Costs***

The Company did not incur any exploratory wells costs during the Current Successor and Predecessor Periods and Prior Predecessor Period. During the year ended December 31, 2015, the Company incurred \$9.5 million of drilling costs for three exploratory wells, one of which was located in the North Park Basin and the other two were outside of the Company's current development area in southern Arkansas and deemed them all dry holes by the end of 2015.

***Reserves***

The proved reserve estimates at December 31, 2017 were prepared by NSAI, our third party independent reserve engineers. The proved reserve estimates at December 31, 2016 and 2015 were 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.

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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, 2017, 2016 and 2015 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)
Balance-December 31, 2014	58,112	188,551	—
Three stream conversion adjustment	(3,352)	—	3,352
Extensions and discoveries <sup>(1)</sup>	6,936	15,849	2,43
Production	(6,072)	(14,11)	(1,676)
Purchases of minerals in place	0,719	3,521	0,234
Revisions to previous estimates <sup>(2)</sup>	1,05	(49,584)	15,578
Balance-December 31, 2015	57,393	144,227	19,918
Extensions, discoveries and infills <sup>(1)</sup>	6,133	15,128	2,142
Production	(4,31)	(11,907)	(1,491)
Sales of minerals in place	(0,1)	(0,343)	(0,035)
Revisions to previous estimates <sup>(2)</sup>	(9,02)	(9,06)	(2,987)
Balance-December 31, 2016	50,096	138,045	17,547
Extensions, discoveries and infills <sup>(1)</sup>	8,47	22,212	3,376
Production	(3,081)	(9,01)	(1,136)
Revisions to previous estimates <sup>(2)</sup>	(2,557)	6,422	3,028
Balance-December 31, 2017	52,928	157,669	22,815
Proved developed reserves:			
December 31, 2015	28,892	77,48	10,359
December 31, 2016	26,313	85,972	9,951
December 31, 2017	25,785	92,718	12,702
Proved undeveloped reserves:			
December 31, 2015	28,501	66,747	9,559
December 31, 2016	23,783	52,073	7,596
December 31, 2017	27,143	64,951	10,113

(1) 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.

At December 31, 2015, horizontal development in the Wattenberg Field resulted in additions in extensions and discoveries of 11,708 MBoe, which is 97% of our total additions of 12,008 MBoe. The remainder of the additions were the result of vertical drilling during the year in the Dorcheat Macedonia Field, Mid-Continent region.

(2) 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 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

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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 them not being centric to current infrastructure. The Company also had negative other engineering revisions of 1,797 MBoe in 2016.

As of December 31, 2015, the Company revised its proved reserves upward by 8,364 Mboe. The Company was successful in offsetting the negative pricing revision of 28,810 Mboe that resulted from a decrease in commodity price from \$94.99 per Bbl WTI and \$4.35 per MMBtu HH for the year ended December 31, 2014 to \$50.28 per Bbl WTI and \$2.59 per MMBtu HH for the year ended December 31, 2015, by reducing the costs to drill and complete wells in both the Rocky Mountain and Mid-Continent regions and improving reserves by increasing productivity of proved developed producing wells in the Wattenberg Field horizontal program. Total positive engineering revisions as of December 31, 2015, were 37,174 MBoe, of which 30,086 MBoe (81%) related to reserve changes in the Wattenberg Field. In the Wattenberg Field, the majority of the positive revisions resulted from a combination of decreased drilling and completion costs of 29% (\$3.0 million per standard reach lateral well as of December 31, 2015 compared to \$4.2 million as of December 31, 2014) and an increase in productivity from horizontal proved developed producing wells which increased the offsetting proved undeveloped reserves. The increase in proved developed producing reserves is primarily attributed to the installation of infrastructure in the east side of the Wattenberg Field. Another significant contribution to the positive reserve revision in the Wattenberg Field is a contract change as of January 1, 2015 which gives the Company ownership of the natural gas liquids from the Company's gas production. This conversion from two stream (wet gas and oil) to three stream (dry gas, natural gas liquids and oil) added 8,560 MBoe to the Company's proved reserves as of December 31, 2015.

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,		
	2017	2016	2015
	(in thousands)		
Future cash flows	\$ 3,307,868	\$ 2,424,415	\$ 3,122,574
Future production costs	(1,490,091)	(1,365,765)	(1,706,607)
Future development costs	(622,344)	(468,804)	(697,045)
Future income tax expense	—	—	—
Future net cash flows	1,195,433	589,846	718,922
10% annual discount for estimated timing of cash flows	(596,935)	(312,891)	(391,106)
Standardized measure of discounted future net cash flows	<u>\$ 598,498</u>	<u>\$ 276,955</u>	<u>\$ 327,816</u>

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

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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,		
	2017	2016	2015
	(in thousands)		
Beginning of period	\$ 276,955	\$ 327,816	\$ 1,107,376
Sale of oil and gas produced, net of production costs	(125,992)	(123,494)	(197,643)
Net changes in prices and production costs	282,112	(126,536)	(1,117,624)
Extensions, discoveries and improved recoveries	103,937	22,800	76,429
Development costs incurred	24,121	19,701	84,180
Changes in estimated development cost	2,122	281,062	178,003
Purchases of minerals in place	—	—	(971)
Sales of minerals in place	—	16	—
Revisions of previous quantity estimates	14,119	(182,938)	(170,277)
Net change in income taxes	—	—	233,086
Accretion of discount	27,696	32,782	134,046
Changes in production rates and other	(6,572)	25,746	1,211
End of period	<u>\$ 598,498</u>	<u>\$ 276,955</u>	<u>\$ 327,816</u>

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2017, 2016 and 2015 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,		
	2017	2016	2015
Oil (per Bbl)	\$ 46.76	\$ 38.42	\$ 44.00
Gas (per Mcf)	\$ 2.45	\$ 2.07	\$ 2.33
Natural gas liquids (per Bbl)	\$ 19.57	12.12	12.90

**NOTE 16 - QUARTERLY FINANCIAL DATA (UNAUDITED)**

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2017 and 2016 (in thousands, except per share data):

	Predecessor		Successor		
	Three Months Ended March 31	April 1, 2017 through April 28, 2017	April 29, 2017 through June 30, 2017	Three Months Ended September 30	Three Months Ended December 31
<b>2017</b>					
Oil and gas sales	\$ 52,559	\$ 16,030	\$ 28,114	\$ 45,232	\$ 50,189
Operating profit (loss) <sup>(1)</sup>	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)

2016	Predecessor Three Months Ended			
	March 31	June 30	September 30	December 31
Oil and gas sales	\$ 44,174	\$ 54,530	\$ 49,325	\$ 47,266
Operating profit loss <sup>(1)</sup>	(2,446)	5,054	5,162	4,509
Net loss	(47,237)	(49,477)	(34,902)	(67,334)
Basic net loss per common share	\$ (0.96)	\$ (1.00)	\$ (0.71)	\$ (1.37)
Diluted net loss per common share	\$ (0.96)	\$ (1.00)	\$ (0.71)	\$ (1.37)

(1) Oil and gas sales less lease operating expense, gas plant and midstream operating expense, 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, 2017. 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, 2017, 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



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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, 2017, 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, 2017, 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, 2017, 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, 2017 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, 2017, 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, 2017, 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 December 31, 2017 (Successor), and for the period from April 29, 2017 to December 31, 2017 (Successor) and the period from January 1, 2017 through April 28, 2017 (Predecessor), and our report dated March 14, 2018 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  
March 14, 2018

### **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, 2017.

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](http://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 17<sup>th</sup> 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, 2017.

**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, 2017.

**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, 2017.

**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, 2017.

**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/ R. Seth Bullock

R. Seth Bullock,  
*Interim Chief Executive Officer*  
*(principal executive officer)*

March 14, 2018

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints R. Seth Bullock, Scott A. Fenoglio, 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.



## INDEX TO EXHIBITS

Exhibit Number	Description
<a href="#">2.1</a>	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)
<a href="#">2.2</a>	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)
<a href="#">2.3</a>	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)
<a href="#">3.1</a>	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)
<a href="#">3.2</a>	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).
<a href="#">10.1</a>	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)
<a href="#">10.2</a>	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)
<a href="#">10.3</a>	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)
<a href="#">10.4</a>	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)
<a href="#">10.5</a>	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)
<a href="#">10.6</a>	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)
<a href="#">10.7</a>	Termination Agreement, dated as of December 28, 2017, by and among Bonanza 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)
<a href="#">10.8*</a>	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)
<a href="#">10.9*</a>	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)
<a href="#">10.10*</a>	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)
<a href="#">10.11*</a>	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)
<a href="#">10.12*</a>	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)
<a href="#">10.13*</a>	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)
<a href="#">10.14*</a>	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)

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<a href="#">10.15*</a>	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)
<a href="#">10.16*</a>	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)
<a href="#">10.17*</a>	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)
<a href="#">10.18*</a>	Employment Letter Agreement dated September 28, 2016, between Bonanza Creek Energy, Inc. and Scott Fenoglio (incorporated by reference to Exhibit 10.34 of the Annual Report on Form 10-K filed on March 16, 2017)
<a href="#">10.19†</a>	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
<a href="#">10.20†</a>	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
<a href="#">16.1</a>	Letter from Hein & Associates LLP (incorporated by reference to Exhibit 16.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 19, 2017)
<a href="#">21.1†</a>	List of subsidiaries
<a href="#">23.1†</a>	Consent of Grant Thornton LLP
<a href="#">23.2†</a>	Consent of Hein & Associates LLP
<a href="#">23.3†</a>	Consent of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc.
<a href="#">31.1†</a>	Certification of the Chief Executive Officer pursuant to Rule 13a- 14(a)
<a href="#">31.2†</a>	Certification of the Chief Financial Officer pursuant to Rule 13a- 14(a)
<a href="#">32.1†</a>	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)
<a href="#">32.2†</a>	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)
<a href="#">99.1†</a>	Report of Independent Petroleum Engineers, Netherland, Sewell & Associates, Inc. for reserves as of December 31, 2017
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



## AMENDMENT NO. 1 AND CONSENT

This AMENDMENT NO. 1 AND CONSENT (this "Amendment") dated as of December 22, 2017 (the "Effective Date") is among Bonanza Creek Energy, Inc., a Delaware corporation (the "Borrower"), the Guarantors (as defined in the Credit Agreement referred to below), the Lenders (as defined below) party hereto (collectively, the "Executing Lenders," and each individually an "Executing Lender"), and KeyBank National Association, as Administrative Agent and as Issuing Lender (as such terms are defined below).

### RECITALS

A. The Borrower and the Guarantors are party to that certain Amended and Restated Credit Agreement dated as of April 28, 2017 (as may be amended, restated or otherwise modified from time to time, the "Credit Agreement") among the Borrower, the Guarantors, the lenders party thereto from time to time (the "Lenders"), and KeyBank National Association, as administrative agent (in such capacity, the "Administrative Agent") and as issuing lender (in such capacity, the "Issuing Lender"). Each capitalized term defined in the Credit Agreement and used herein without definition shall have the meaning assigned to such term in the Credit Agreement, unless expressly provided to the contrary.

B. Pursuant to that certain Exchange and Purchase Agreement dated December 22, 2017 (the "Trade Agreement") with Confluence DJ, LLC and Kerr-McGee Oil & Gas Onshore LP, a copy of which is attached hereto as Annex A, Bonanza Creek Energy Operating Company, LLC, a Delaware limited liability company ("BCEOC"), desires to swap approximately 600 acres in Weld County, Colorado and one producing well (such 600 acres and the one producing well, the "Subject Properties").

C. The Executing Lenders wish to, subject to the terms and conditions of this Amendment, (i) amend the Credit Agreement and (ii) consent to the Disposition of the Subject Properties, in each case, as provided herein.

THEREFORE, the Borrower, the Guarantors, the Administrative Agent, the Issuing Lender, and the Executing Lenders hereby agree as follows:

**Section 1. Defined Terms.** As used in this Amendment, each of the terms defined in the opening paragraph and the Recitals above shall have the meanings assigned to such terms therein.

**Section 2. Other Definitional Provisions.** Article, Section, Schedule, and Exhibit references are to Articles and Sections of and Schedules and Exhibits to this Amendment, unless otherwise specified. All references to instruments, documents, contracts, and agreements are references to such instruments, documents, contracts, and agreements as the same may be amended, supplemented, and otherwise modified from time to time, unless otherwise specified. The words "hereof", "herein", and "hereunder" and words of similar import when used in this Amendment shall refer to this Amendment as a whole and not to any particular provision of this Amendment. The term "including" means "including, without limitation,". Paragraph headings have been inserted

in this Amendment as a matter of convenience for reference only and it is agreed that such paragraph headings are not a part of this Amendment and shall not be used in the interpretation of any provision of this Amendment.

**Section 3. Amendment to Credit Agreement.**

(a) Clause (c)(iv)(B) of Section 6.04 of the Credit Agreement is hereby amended by replacing the first reference to “500 acres” with a reference to “1000 acres”.

**Section 4. Consent.** Subject to the terms and conditions of this Amendment, the Executing Lenders hereby consent to the Disposition of the Subject Properties so long as (a) BCEOC receives at least \$97,000 in cash consideration, (b) BCEOC receives at least 590 acres in Weld County, Colorado in exchange for the Subject Properties (the “Received Properties”), (c) the Subject Properties do not exceed 650 acres in total, and (d) the swap of the Subject Properties is otherwise on the terms as set forth in the Trade Agreement attached hereto. The consent by the Executing Lenders described in this Section 4 is strictly limited to the Disposition of the Subject Properties. Such consent shall not be construed to be a consent to, or a waiver of, non-compliance with any terms, provisions, covenants, warranties or agreements contained in the Credit Agreement or in any of the other Loan Documents other than Section 6.04 of the Credit Agreement solely as to the Disposition of the Subject Properties as expressly set forth herein.

**Section 5. Representations and Warranties.** The Borrower and each Guarantor represents and warrants that: (a) the representations and warranties contained in the Credit Agreement and the representations and warranties contained in the other Loan Documents are true and correct in all material respects (unless already qualified by materiality or Material Adverse Change in the text thereof, in which case, such representations and warranties shall be true and correct in all respects) on and as of the Effective Date as if made on and as of such date, except to the extent that any such representation or warranty expressly relates solely to an earlier date, in which case it shall have been true and correct in all material respects (unless already qualified by materiality or Material Adverse Change in the text thereof, in which case, such representations and warranties shall be true and correct in all respects) as of such earlier date; (b) no Default has occurred and is continuing; (c) the execution, delivery and performance of this Amendment are within the corporate or limited liability company, as applicable, power and authority of such Person and have been duly authorized by appropriate corporate or limited liability company, as applicable, action and proceedings; (d) this Amendment constitutes the legal, valid, and binding obligation of such Person enforceable in accordance with its terms, except as such enforceability may be limited by any applicable Debtor Relief Laws; (e) no consent, order, authorization, or approval or other action by, and no notice to or filing with, any Governmental Authority or any other Person are required for the due execution, delivery, and performance by the Borrower or any Guarantor in connection with this Amendment or the consummation of the transactions contemplated hereby; (f) the Liens under the Security Instruments are valid and subsisting and secure Borrower’s obligations under the Loan Documents; and (g) as to each Guarantor, it has no defenses to the enforcement of its Guaranty.

**Section 6. Conditions to Effectiveness.** This Amendment shall become effective on the Effective Date and enforceable against the parties hereto upon the occurrence of the following conditions precedent:

(a) The Administrative Agent shall have received multiple original counterparts, as requested by the Administrative Agent, of this Amendment duly and validly executed and delivered by duly authorized officers of the Borrower, the Guarantors, the Issuing Lender and the Majority Lenders.

(b) The Borrower shall deliver a certificate of a Responsible Financial Officer certifying that the consideration received in respect of such Disposition is equal to or greater than the fair market value of such Oil and Gas Properties.

(c) No Default shall have occurred and be continuing as of the Effective Date.

(d) The representations and warranties in this Amendment shall be true and correct in all material respects.

(e) The Borrower shall have paid all costs and expenses payable pursuant to Section 9.01(a) of the Credit Agreement to the extent invoices for such fees, costs, and expenses have been presented to the Borrower at least two Business Days prior to the Effective Date.

**Section 7. Acknowledgments and Agreements.**

(a) The Borrower acknowledges that on the date hereof all Secured Obligations are payable without defense, offset, counterclaim or recoupment.

(b) The Administrative Agent, the Issuing Lender and the Lenders hereby expressly reserve all of their rights, remedies, and claims under the Loan Documents. Nothing in this Amendment shall constitute a waiver or relinquishment of (i) (1) any Default or Event of Default under any of the Loan Documents, (2) any of the agreements, terms or conditions contained in any of the Loan Documents, or (3) any rights or remedies of the Administrative Agent, the Issuing Lender or any Lender with respect to the Loan Documents, or (ii) the rights of the Administrative Agent, the Issuing Lender or any Lender to collect the full amounts owing to them under the Loan Documents.

(c) Each of the Borrower, the Administrative Agent, the Issuing Lender and the Lenders does hereby adopt, ratify, and confirm the Credit Agreement, as amended and otherwise modified hereby, and acknowledges and agrees that the Credit Agreement, as amended and otherwise modified hereby, is and remains in full force and effect, and the Borrower acknowledges and agrees that its liabilities and obligations under the Credit Agreement, as amended and otherwise modified hereby, are not impaired in any respect by this Amendment.

(d) From and after the Effective Date, all references to the Credit Agreement and the Loan Documents shall mean such Credit Agreement and such Loan Documents as amended and otherwise modified by this Amendment.

(e) This Amendment is a Loan Document for the purposes of the provisions of the other Loan Documents. Without limiting the foregoing, any breach of representations, warranties, and covenants under this Amendment shall be a Default or Event of Default, as applicable, under the Credit Agreement.

(f) On or before the date that is thirty (30) days after the date of the Disposition of the Subject Properties pursuant to the Trade Agreement, the Loan Parties shall execute and enter into Mortgages (or supplements to existing Mortgages) in order to grant an Acceptable Security Interest in the Received Properties.

**Section 8. Reaffirmation of Guaranty.** Each Guarantor hereby ratifies, confirms, acknowledges and agrees that its obligations under its Guaranty, as amended and otherwise modified hereby, are in full force and effect and that such Guarantor continues to unconditionally and irrevocably guarantee the full and punctual payment, when due, whether at stated maturity or earlier by acceleration or otherwise, of all of the Guaranteed Obligations (as defined in the Guaranty), as such Guaranteed Obligations may have been amended by this Amendment, and its execution and delivery of this Amendment does not indicate or establish an approval or consent requirement by the Guarantor in connection with the execution and delivery of amendments, consents or waivers to the Credit Agreement or any of the other Loan Documents.

**Section 9. Counterparts.** This Amendment may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement. Delivery of an executed counterpart of a signature page of this Amendment by facsimile or in electronic (i.e., “pdf” or “tif”) format shall be effective as delivery of a manually executed counterpart of this Amendment.

**Section 10. Successors and Assigns.** This Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted pursuant to the Credit Agreement.

**Section 11. Severability.** Any provision of this Amendment which is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective only to the extent of such prohibition or unenforceability without invalidating the remainder of such provision or the remaining provisions hereof or thereof or affecting the validity or enforceability of such provision in any other jurisdiction.

**Section 12. Governing Law.** This Amendment shall be deemed to be a contract made under and shall be governed by and construed in accordance with the laws of the State of New York.

**Section 13. Entire Agreement. THIS AMENDMENT, THE CREDIT AGREEMENT AS AMENDED BY THIS AMENDMENT, THE NOTES, AND THE OTHER LOAN DOCUMENTS CONSTITUTE THE ENTIRE UNDERSTANDING AMONG THE PARTIES HERETO WITH RESPECT TO THE SUBJECT MATTER HEREOF AND SUPERSEDE ANY PRIOR AGREEMENTS, WRITTEN OR ORAL, WITH RESPECT THERETO.**

**THERE ARE NO UNWRITTEN ORAL AGREEMENTS AMONG THE PARTIES.**

*[signature pages follow]*

EXECUTED effective as of the date first above written.

**BORROWER: BONANZA CREEK ENERGY, INC.**

By: \_\_\_\_\_  
Name:  
Title:

**GUARANTORS: BONANZA CREEK ENERGY OPERATING COMPANY, LLC**

By: \_\_\_\_\_  
Name:  
Title:

**BONANZA CREEK ENERGY RESOURCES,  
LLC**

By: \_\_\_\_\_  
Name:  
Title:

**BONANZA CREEK ENERGY MIDSTREAM,  
LLC**

By: \_\_\_\_\_  
Name:  
Title:

**BONANZA CREEK ENERGY UPSTREAM  
LLC**

By: \_\_\_\_\_  
Name:  
Title:

**HOLMES EASTERN COMPANY, LLC**

By: \_\_\_\_\_  
Name:  
Title:

**ROCKY MOUNTAIN INFRASTRUCTURE, LLC**

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**ADMINISTRATIVE AGENT/  
ISSUING LENDER/LENDER:**

**KEYBANK NATIONAL ASSOCIATION**, as Administrative Agent, Issuing Lender,  
and a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**COMPASS BANK**, as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**SOCIÉTÉ GÉNÉRALE**, as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**BMO HARRIS FINANCING, INC.**, as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**WELLS FARGO BANK. N.A.**, as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**JPMORGAN CHASE BANK, N.A.**, as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:** (i)  
**ROYAL BANK OF CANADA, as a Lender**

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:** **CADENCE BANK, N.A., as a Lender**

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:** **IBERIABANK, as a Lender**

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:** **THE BANK OF NOVA SCOTIA, as a Lender**

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

## AMENDMENT NO. 2

This AMENDMENT NO. 2 (this "Amendment") dated as of February 2, 2018 (the "Effective Date") is among Bonanza Creek Energy, Inc., a Delaware corporation (the "Borrower"), the Guarantors (as defined in the Credit Agreement referred to below), the Lenders (as defined below) party hereto (collectively, the "Executing Lenders," and each individually an "Executing Lender"), and KeyBank National Association, as Administrative Agent and as Issuing Lender (as such terms are defined below).

### RECITALS

A. The Borrower and the Guarantors are party to that certain Amended and Restated Credit Agreement dated as of April 28, 2017 (as amended by that certain Amendment No. 1 and Consent dated effective as of December 22, 2017 and as the same may be further amended, restated or otherwise modified from time to time, the "Credit Agreement") among the Borrower, the Guarantors, the lenders party thereto from time to time (the "Lenders"), and KeyBank National Association, as administrative agent (in such capacity, the "Administrative Agent") and as issuing lender (in such capacity, the "Issuing Lender"). Each capitalized term defined in the Credit Agreement and used herein without definition shall have the meaning assigned to such term in the Credit Agreement, unless expressly provided to the contrary.

B. The Executing Lenders wish to, subject to the terms and conditions of this Amendment, amend the Credit Agreement as provided herein.

THEREFORE, the Borrower, the Guarantors, the Administrative Agent, the Issuing Lender, and the Executing Lenders hereby agree as follows:

**Section 1. Defined Terms.** As used in this Amendment, each of the terms defined in the opening paragraph and the Recitals above shall have the meanings assigned to such terms therein.

**Section 2. Other Definitional Provisions.** Article, Section, Schedule, and Exhibit references are to Articles and Sections of and Schedules and Exhibits to this Amendment, unless otherwise specified. All references to instruments, documents, contracts, and agreements are references to such instruments, documents, contracts, and agreements as the same may be amended, supplemented, and otherwise modified from time to time, unless otherwise specified. The words "hereof", "herein", and "hereunder" and words of similar import when used in this Amendment shall refer to this Amendment as a whole and not to any particular provision of this Amendment. The term "including" means "including, without limitation,". Paragraph headings have been inserted in this Amendment as a matter of convenience for reference only and it is agreed that such paragraph headings are not a part of this Amendment and shall not be used in the interpretation of any provision of this Amendment.

**Section 3. Amendments to Credit Agreement.**

(a) Section 5.06 of the Credit Agreement is hereby amended by amending and restating clause (d) thereof in its entirety to read as follows:



(d) [Reserved]

(b) Section 6.15(a) of the Credit Agreement is hereby amended by amending and restating clauses (i) and (ii) thereof of in their entirety to read as follows and by adding a new sentence to the end thereof to read as follows:

*(i) for the 24-month period from the date such hedging trade or transaction is created, the greater of (x) 100% of the forecasted production of natural gas, oil, and natural gas liquids and condensate, calculated separately and on a monthly basis, in each case, from the PDP Reserves as set forth on the most recent Engineering Report, and (y) 85% of the forecasted production of natural gas, oil, and natural gas liquids and condensate, calculated separately and on a monthly basis, in each case, from the Proven Reserves as set forth on the most recent Engineering Report, and*

*(ii) for the 36-month period commencing with the second anniversary of the date such hedging trade or transaction is created, the greater of (x) 85% of the forecasted production of natural gas, oil, and natural gas liquids and condensate, calculated separately and on a monthly basis, in each case, from the PDP Reserves as set forth on the most recent Engineering Report, and (y) 65% of the forecasted production of natural gas, oil, and natural gas liquids and condensate, calculated separately and on a monthly basis, in each case, from the Proven Reserves as set forth on the most recent Engineering Report.*

*Notwithstanding anything to the contrary contained in this Section 6.15(a), until the delivery of the Independent Engineering Report dated effective as of January 1, 2018 due on or about April 1, 2018, the most recent Engineering Report for purposes of this Section 6.15(a) shall be deemed to be the preliminary year end 2017 report attached hereto as Schedule 6.15*

(c) The Credit Agreement is hereby amended to add a new Schedule 6.15 in the form attached hereto.

**Section 4. Representations and Warranties.** The Borrower and each Guarantor represents and warrants that: (a) the representations and warranties contained in the Credit Agreement and the representations and warranties contained in the other Loan Documents are true and correct in all material respects (unless already qualified by materiality or Material Adverse Change in the text thereof, in which case, such representations and warranties shall be true and correct in all respects) on and as of the Effective Date as if made on and as of such date, except to the extent that any such representation or warranty expressly relates solely to an earlier date, in which case it shall have been true and correct in all material respects (unless already qualified by materiality or Material Adverse Change in the text thereof, in which case, such representations and warranties shall be true and correct in all respects) as of such earlier date; (b) no Default has occurred and is continuing; (c) the execution, delivery and performance of this Amendment are within the corporate or limited liability company, as applicable, power and authority of such Person and have

been duly authorized by appropriate corporate or limited liability company, as applicable, action and proceedings; (d) this Amendment constitutes the legal, valid, and binding obligation of such Person enforceable in accordance with its terms, except as such enforceability may be limited by any applicable Debtor Relief Laws; (e) no consent, order, authorization, or approval or other action by, and no notice to or filing with, any Governmental Authority or any other Person are required for the due execution, delivery, and performance by the Borrower or any Guarantor in connection with this Amendment or the consummation of the transactions contemplated hereby; (f) the Liens under the Security Instruments are valid and subsisting and secure Borrower's obligations under the Loan Documents; and (g) as to each Guarantor, it has no defenses to the enforcement of its Guaranty.

**Section 5. Conditions to Effectiveness.** This Amendment shall become effective on the Effective Date and enforceable against the parties hereto upon the occurrence of the following conditions precedent:

(a) The Administrative Agent shall have received multiple original counterparts, as requested by the Administrative Agent, of this Amendment duly and validly executed and delivered by duly authorized officers of the Borrower, the Guarantors, the Issuing Lender and the Majority Lenders.

(b) No Default shall have occurred and be continuing as of the Effective Date.

(c) The representations and warranties in this Amendment shall be true and correct in all material respects.

(d) The Borrower shall have paid all costs and expenses payable pursuant to Section 9.01(a) of the Credit Agreement to the extent invoices for such fees, costs, and expenses have been presented to the Borrower at least two Business Days prior to the Effective Date.

**Section 6. Acknowledgments and Agreements.**

(a) The Borrower acknowledges that on the date hereof all Secured Obligations are payable without defense, offset, counterclaim or recoupment.

(b) The Administrative Agent, the Issuing Lender and the Lenders hereby expressly reserve all of their rights, remedies, and claims under the Loan Documents. Nothing in this Amendment shall constitute a waiver or relinquishment of (i) (1) any Default or Event of Default under any of the Loan Documents, (2) any of the agreements, terms or conditions contained in any of the Loan Documents, or (3) any rights or remedies of the Administrative Agent, the Issuing Lender or any Lender with respect to the Loan Documents, or (ii) the rights of the Administrative Agent, the Issuing Lender or any Lender to collect the full amounts owing to them under the Loan Documents.

(c) Each of the Borrower, the Administrative Agent, the Issuing Lender and the Lenders does hereby adopt, ratify, and confirm the Credit Agreement, as amended and otherwise modified hereby, and acknowledges and agrees that the Credit Agreement, as amended and otherwise

modified hereby, is and remains in full force and effect, and the Borrower acknowledges and agrees that its liabilities and obligations under the Credit Agreement, as amended and otherwise modified hereby, are not impaired in any respect by this Amendment.

(d) From and after the Effective Date, all references to the Credit Agreement and the Loan Documents shall mean such Credit Agreement and such Loan Documents as amended and otherwise modified by this Amendment.

(e) This Amendment is a Loan Document for the purposes of the provisions of the other Loan Documents. Without limiting the foregoing, any breach of representations, warranties, and covenants under this Amendment shall be a Default or Event of Default, as applicable, under the Credit Agreement.

**Section 7. Reaffirmation of Guaranty.** Each Guarantor hereby ratifies, confirms, acknowledges and agrees that its obligations under its Guaranty, as amended and otherwise modified hereby, are in full force and effect and that such Guarantor continues to unconditionally and irrevocably guarantee the full and punctual payment, when due, whether at stated maturity or earlier by acceleration or otherwise, of all of the Guaranteed Obligations (as defined in the Guaranty), as such Guaranteed Obligations may have been amended by this Amendment, and its execution and delivery of this Amendment does not indicate or establish an approval or consent requirement by the Guarantor in connection with the execution and delivery of amendments, consents or waivers to the Credit Agreement or any of the other Loan Documents.

**Section 8. Counterparts.** This Amendment may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same agreement. Delivery of an executed counterpart of a signature page of this Amendment by facsimile or in electronic (i.e., "pdf" or "tif") format shall be effective as delivery of a manually executed counterpart of this Amendment.

**Section 9. Successors and Assigns.** This Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted pursuant to the Credit Agreement.

**Section 10. Severability.** Any provision of this Amendment which is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective only to the extent of such prohibition or unenforceability without invalidating the remainder of such provision or the remaining provisions hereof or thereof or affecting the validity or enforceability of such provision in any other jurisdiction.

**Section 11. Governing Law.** This Amendment shall be deemed to be a contract made under and shall be governed by and construed in accordance with the laws of the State of New York.

**Section 12. RELEASE.** THE BORROWER ACKNOWLEDGES THAT ON THE DATE HEREOF ALL OBLIGATIONS ARE PAYABLE WITHOUT DEFENSE, OFFSET, COUNTERCLAIM OR RECOUPMENT. IN ADDITION, EACH OF THE BORROWER, THE

GUARANTORS AND EACH OF THEIR RESPECTIVE SUBSIDIARIES (FOR THEMSELVES AND THEIR RESPECTIVE SUCCESSORS, AGENTS, ASSIGNS, TRANSFEREES, OFFICERS, DIRECTORS, EMPLOYEES, SHAREHOLDERS, ATTORNEYS AND AGENTS) HEREBY RELEASES ANY AND ALL CLAIMS, CAUSES OF ACTION OR OTHER DISPUTES IT MAY HAVE AGAINST THE ADMINISTRATIVE AGENT, THE ISSUING LENDER, ANY OF THE LENDERS, LEGAL COUNSEL TO THE ADMINISTRATIVE AGENT, THE ISSUING LENDER OR ANY OF THE LENDERS, CONSULTANTS HIRED BY ANY OF THE FOREGOING, OR ANY OF THEIR RESPECTIVE AFFILIATES, SUBSIDIARIES, SHAREHOLDERS, AGENTS, DIRECTORS, OFFICERS, EMPLOYEES, REPRESENTATIVES, SUCCESSORS OR ASSIGNS OF ANY KIND OR NATURE ARISING OUT OF, RELATED TO, OR IN ANY WAY CONNECTED WITH, THE CREDIT AGREEMENT OR THE LOAN DOCUMENTS, IN EACH CASE WHICH MAY HAVE ARISEN ON OR BEFORE THE DATE OF THIS AMENDMENT. EACH OF THE BORROWER, THE GUARANTORS AND THEIR RESPECTIVE SUBSIDIARIES HEREBY ACKNOWLEDGES THAT IT HAS READ THIS AMENDMENT AND HAS CONFERRED WITH ITS COUNSEL AND ADVISORS REGARDING ITS CONTENT, INCLUDING THIS SECTION 12, AND IS FREELY AND VOLUNTARILY ENTERING INTO THIS AMENDMENT, AND HEREBY AGREES TO WAIVE ANY CLAIM THAT THE TERMS OF THIS AMENDMENT (INCLUDING, WITHOUT LIMITATION, THE RELEASES CONTAINED HEREIN) ARE INVALID OR OTHERWISE UNENFORCEABLE.

**Section 13. Entire Agreement. THIS AMENDMENT, THE CREDIT AGREEMENT AS AMENDED BY THIS AMENDMENT, THE NOTES, AND THE OTHER LOAN DOCUMENTS CONSTITUTE THE ENTIRE UNDERSTANDING AMONG THE PARTIES HERETO WITH RESPECT TO THE SUBJECT MATTER HEREOF AND SUPERSEDE ANY PRIOR AGREEMENTS, WRITTEN OR ORAL, WITH RESPECT THERETO.**

**THERE ARE NO UNWRITTEN ORAL AGREEMENTS AMONG THE PARTIES.**

*[signature pages follow]*

EXECUTED effective as of the date first above written.

**BORROWER:**

**BONANZA CREEK ENERGY, INC.**

By: \_\_\_\_\_  
Name:  
Title:

**GUARANTORS:**

**BONANZA CREEK ENERGY OPERATING COMPANY, LLC**

By: \_\_\_\_\_  
Name:  
Title:

**BONANZA CREEK ENERGY RESOURCES,  
LLC**

By: \_\_\_\_\_  
Name:  
Title:

**BONANZA CREEK ENERGY MIDSTREAM,  
LLC**

By: \_\_\_\_\_

Name:  
Title:

**BONANZA CREEK ENERGY UPSTREAM  
LLC**

By: \_\_\_\_\_  
Name:  
Title:

**HOLMES EASTERN COMPANY, LLC**

By: \_\_\_\_\_  
Name:  
Title:

**ROCKY MOUNTAIN INFRASTRUCTURE, LLC**

By: \_\_\_\_\_  
Name:  
Title:

**ADMINISTRATIVE AGENT/  
ISSUING LENDER/LENDER:**

**KEYBANK NATIONAL ASSOCIATION**, as Administrative Agent, Issuing Lender,  
and a Lender

By: \_\_\_\_\_  
Name:  
Title:

**LENDER:**

**COMPASS BANK**, as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**SOCIÉTÉ GÉNÉRALE**, as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**BMO HARRIS FINANCING, INC.,** as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**WELLS FARGO BANK, N.A.,** as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**JPMORGAN CHASE BANK, N.A.,** as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

(i)  
**ROYAL BANK OF CANADA,** as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**CADENCE BANK, N.A.,** as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**IBERIABANK,** as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**LENDER:**

**THE BANK OF NOVA SCOTIA,** as a Lender

By: \_\_\_\_\_  
Name: \_\_\_\_\_  
Title: \_\_\_\_\_

**SCHEDULE 6.15**

#5604213

1" = "1" "#5626658" "" #5626658

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

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

Bonanza Creek Energy Resources, LLC, a Delaware limited liability company

Bonanza Creek Energy Upstream LLC, a Delaware limited liability company

Bonanza Creek Energy Midstream, LLC, a Delaware limited liability company

Holmes Eastern Company, LLC, a Delaware limited liability company

Rocky Mountain Infrastructure, LLC, a Delaware limited liability company



**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We have issued our reports dated March 14, 2018, 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, 2017. We consent to the incorporation by reference of said reports in the Registration Statement of Bonanza Creek Energy, Inc. on Form S-8 (File No. 333-217545).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma  
March 14, 2018

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in the Registration Statement on Form S-8 (File No. 333-217545) 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, 2017.

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.

Hein & Associates LLP

Denver, Colorado  
March 14, 2018

**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, 2017. We further consent to the incorporation by reference thereof into Bonanza Creek Energy, Inc.'s Registration Statements on Form S-8 (Registration Nos. 333-179207 and 333-206399) and on Form S-3 (Registration Nos. 333-186019, 333-192258, 333-197413, 333-197901, and 333-206398).

**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  
March 14, 2018

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

I, Seth Bullock, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 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: March 14, 2018

/s/ Seth Bullock

---

Seth Bullock

*Interim Chief Executive Officer*

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

I, Scott A. Fenoglio, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 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: March 14, 2018

/s/ Scott A. Fenoglio

Scott A. Fenoglio

*Senior Vice President, Finance & Planning*

**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, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Seth Bullock, Interim 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: March 14, 2018

/s/ Seth Bullock

---

Seth Bullock

*Interim Chief Executive Officer*

**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, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Scott A. Fenoglio, Senior Vice President, Finance & Planning 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: March 14, 2018

/s/ Scott A. Fenoglio

---

Scott A. Fenoglio

Senior Vice President, Finance & Planning

January 24, 2018

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, 2017, 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 Arkansas and 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, 2017, to be:

Category	Net Reserves			Future Net Revenue (M\$)	
	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	24,337.9	12,221.3	88,373.0	704,319.6	432,906.0
Proved Developed Non-Producing	1,446.8	480.7	4,345.4	52,845.0	37,079.8
Proved Undeveloped	27,143.4	10,113.3	64,950.9	438,269.9	128,511.8
<b>Total Proved</b>	<b>52,928.0</b>	<b>22,815.3</b>	<b>157,669.4</b>	<b>1,195,434.5</b>	<b>598,497.6</b>

*Totals may not add because of rounding.*

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 2017. For oil and NGL volumes, the average West Texas Intermediate spot price of \$51.34 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 \$2.976 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 \$46.76 per barrel of oil, \$19.57 per barrel of NGL, and \$2.451 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.

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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

/s/ C.H. (Scott) Rees III

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

/s/ Benjamin W. Johnson

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

/s/ John G. Hattner

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

Date Signed: January 24, 2018

Date Signed: January 24, 2018

BWJ:AHA

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## 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 2007 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 2007 Petroleum Resources Management System:*

*Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.*

*Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which 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 which will require additional completion work or future recompletion prior to start of production. 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

## DEFINITIONS OF OIL AND GAS RESERVES

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

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.

(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.





